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March 22, 2017

VIA, ELECTRONIC FILING
The Honorable Jocelyn Boyd
Chief Clerk and Administrator
The Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

Re: • Docket Number 2017-2-E

Dear Ms. Boyd:

Enclosed for filing please find the Direct Testimony of Dr. Ben Johnson on behalf of Intervenor, South Carolina Solar Business Alliance, LLC, Cover Sheet and Certificate of Service.

All parties of record have been served. Please notify the undersigned if you there is anything else you may need.

Respectfully Submitted,

/S/________________
Richard L. Whitt

RLW/cas

DIRECT TESTIMONY OF

Dr. Ben Johnson

ON BEHALF OF THE

SOUTH CAROLINA SOLAR BUSINESS ALLIANCE

Before the

PUBLIC SERVICE COMMISSION

OF SOUTH CAROLINA

DOCKET NO. 2017-2-E

Introduction

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Ben Johnson, 5600 Pimlico Drive, Tallahassee, Florida. I am a Consulting Economist and President of Ben Johnson Associates, Inc., a consulting firm that specializes in public utility regulation.

Q. ON WHOSE BEHALF ARE YOU PROVIDING THIS TESTIMONY?

A. I have been retained by the South Carolina Solar Business Alliance, LLC ("SBA") to assist in preparing and presenting evidence in this proceeding with respect to the Public

Utility Regulatory Policies Act of 1978 ("PURPA"), the avoided costs of South Carolina Electric & Gas ("SCE&G" or "the Company") and proposed changes to Rate PR-2.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISION?

A. Yes. The earliest case I can recall was Docket No. 77-354-E which was a 1978 case involving Carolina Power & Light Company. I've worked in several other South Carolina proceedings since that time, involving electric, telephone and water utilities. The most recent case was Docket No. 1995-1192-E (starting in late 2015 and ending in early 2016). However, this case involved preparation of several reports, rather than testimony. It was resolved by a settlement of the interested parties after these reports were provided to the Office of Regulatory Staff ("ORS") and other parties, so it was not necessary to submit testimony to the Commission.

Q. CAN YOU PLEASE BRIEFLY DESCRIBE YOUR OTHER QUALIFICATIONS?

A. Yes. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics.

I have been actively involved in public utility regulation since 1974. Over the past four decades I've analyzed a wide range of different issues involving many types of regulated firms, participated in more than 400 regulatory dockets, and provided expert testimony on more than 300 occasions before state and federal courts and utility regulatory commissions in 35 states, two Canadian provinces, and the District of Columbia.

My work in North Carolina is particularly noteworthy, since it involved some of the same utilities that operate in South Carolina, and because some of these proceedings dealt with issues that are similar to the ones I am testifying about in this proceeding: These cases include Docket Number E-100, Sub 53, a 1986 proceeding concerning avoided costs and rates to be paid to Qualified Facilities ("QF's); Docket Number E-100, Sub 57, a 1988 proceeding concerning QF rates and avoided costs; Docket Number E-100, Sub 66, a 1993 proceeding concerning QF rates and avoided costs; Docket Number E-100, Sub 74, a 1995 proceeding concerning QF rates and avoided costs; Docket Number E-100, Sub 75, a 1995 proceeding concerning Least Cost Integrated Resource Planning; Docket No. E-2, Sub 966, an avoided cost arbitration between Capital Power Corporation and Progress Energy Carolina, Inc.; Docket No. E-100, Sub 136 a 2012 proceeding concerning QF rates and avoided costs, Docket No. E-100, Sub 140 a 2014 proceeding concerning avoided costs and Docket No. E-100, Sub 148 a 2016 proceeding concerning QF rates and avoided costs.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I begin with some rate comparisons. I then discuss various aspects of PURPA from my perspective as an economist. Next, I discuss various methodologies that can be used to estimate avoided costs. In the next two sections I discuss some independently developed estimates of the Company's long run avoided capacity costs and energy costs, respectively. Next, I provide some comparisons between the Company's proposed QF rates and my independently developed estimates of its long run avoided capacity and energy costs. Finally, I make some recommendations concerning appropriate action which the Commission could take in this proceeding concerning the Company's QF rate proposals.

Rate Comparisons

Q. HAVE YOU COMPARED THE QF RATES PROPOSED IN THIS CASE TO ANALOGOUS RATES APPROVED IN PAST PROCEEDINGS?

A. Yes. SCE&G's current QF rates were approved by the Commission in Order No. 2016-297, dated April 29, 2016. Analogous rates for Duke Energy Carolinas ("DEC" and Duke Energy Progress ("DEP") were approved by the Commission in Order No. 2016-349, dated May 12, 2016. I compared these approved rates to the QF rates that have been proposed in this proceeding. Before presenting my numerical comparisons, some structural differences should be noted.

The current and proposed SCE&G tariffs establish standard offer rates for small solar power producers and other QF's with a capacity greater than 100 kW and equal to or less than 80 MW. The Duke tariffs are applicable to QF's with capacity of up to just 2 MW. The SCE&G tariffs separately set forth rates for QF's interconnecting at transmission and distribution voltage levels, although the rates are identical. In contrast, Duke's tariff establishes lower rates for projects interconnected at transmission voltage than at distribution voltage.

The SCE&G tariffs provides separate rates for 5 year blocks. The currently approved rates are for the years 2016 – 2020, 2021 – 2025 and 2026 – 2030, while the proposed rates are for the years 2017 – 2021, 2022 – 2026 and 2027 – 2031. This tariff structure apparently gives QF's the option of contracting to sell capacity and energy for up to 15 years, with the QF being paid different rates during each 5 year period. Duke's tariffs also provide long term rates, but they are structured differently. A QF that doesn't opt for the "variable" rate can enter into a 5 or 10 year commitment and is paid a "fixed long-term" rate over the entire commitment period, rather than a rate that increases each year with inflation. Due to inflation and other factors, Duke's 10 year rates are higher than its 5 year rates. In contrast, SCE&G's proposed energy rate for 2022 – 2026 is lower than the proposed rates for the prior and subsequent 5 year periods, reflecting the expected impact of the new VC Summer nuclear units, among other factors.

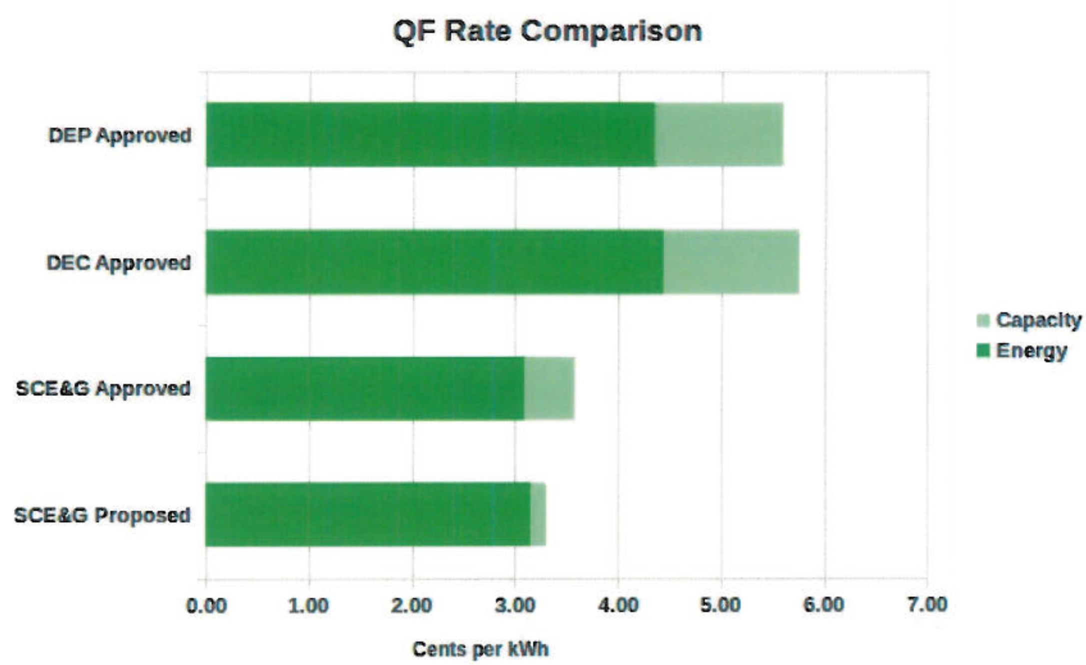
All three utilities pay higher rates during the summer, and lower rates during the rest of the year, although the seasons are defined a little differently. Duke and SCE&G both distinguish between on-peak and off-peak hours, but they define these periods differently. Another difference is that Duke averages its energy rates to a greater degree than SCE&G. For instance, Duke pays the same On-Peak energy rate during the Summer and Non-Summer months, and it pays the same Off-Peak energy rate year-round. In contrast, SCE&G pays different On-Peak and Off-Peak energy rates in the Summer months than in the Non-Summer months.

Q. CAN YOU MEANINGFULLY COMPARE THESE DIFFERENT RATES DESPITE THESE STRUCTURAL DIFFERENCES?

A. Yes. To take into account these differences, I compared the rates on a composite or weighted average basis, as they apply to a typical solar facility. More specifically, I looked at the rates applicable during each hour of each day of the year, and applied them to the volume of energy which can reasonably be expected from a typical QF solar facility to determine the total payments that would be received by the QF. The total payments were then divided by the total kWh which were expected to be produced by the QF, in order to calculate an overall composite rate per kWh. This procedure took into account how the Summer and Non-Summer seasons are defined, as well as how the peak and non-peak time periods are defined in each of the tariffs.

Q. WHAT IS REVEALED BY THIS COMPARISON?

A. This composite analysis demonstrates that SCE&G's proposed QF rates are far lower than the rates approved by this Commission for Duke Progress and Duke Carolina. The proposed tariff would widen an existing discrepancy between SCE&G's rates and those of the Duke utilities, as shown in the following graph:



The Duke Progress and Duke Carolinas rates differ just slightly, primarily due to differences in their generating facilities and load patterns. In contrast, SCE&G's rates are dramatically lower. Based upon my experience, I would expect such large differences in the QF rates would be attributable to differences in the methodological approach and input assumptions being used by SCE&G, rather than differences in their service areas. This is particularly likely with respect to the proposed capacity rates, since the discrepancies are quite extreme, as shown in the following tables:

Difference in QF Rates: Duke Progress Current versus SCE&G Proposed			
	Energy	Capacity	Total
Duke Progress	4.352 cents	1.242 cents	5.594 cents
SCE&G – Proposed	3.156 cents	0.149 cents	3.306 cents
Difference (2-1)	-1.196 cents	-1.093 cents	-2.288 cents
Percent Difference (3/1)	-27.5%	-88.0 %	-40.9 %

Difference in QF Rates: Duke Carolinas Current versus SCE&G Proposed			
	Energy	Capacity	Total
Duke Carolinas	4.433 cents	1.321 cents	5.754 cents
SCE&G – Proposed	3.156 cents	0.149 cents	3.306 cents
Difference (6-5)	-1.277 cents	-1.171 cents	-2.448 cents
Percent Difference (7/5)	-28.8 %	-88.7 %	-42.5 %

As shown in the above tables, in its proposed tariff, SCE&G is offering to pay QF's 88.0% less for capacity than a QF would receive if it were located in the service area of Duke Progress, and 88.7% less than it would receive if it were located in the service area of Duke Carolinas. These extreme differences send a strong price signal to the state's QF developers, nearly forcing them to build in the parts of the state served by Duke Carolinas and Duke Energy, rather than in SCE&G's service area.

Q. ARE SCE&G'S ENERGY OR CAPACITY COSTS DRAMATICALLY LOWER THAN THOSE OF DUKE PROGRESS OR DUKE ENERGY?

A. There is no reason to think so. To the contrary, Duke is a much larger utility, giving it greater negotiating leverage in dealing with suppliers. Hence, it wouldn't be surprising if SCE&G were to incur slightly higher costs when building and operating generating plants (per kW of installed nameplate capacity or per kWh of electricity produced) – not significantly lower costs. Absent a substantial cost advantage when building and operating generating plants, one would logically expect SCE&G's costs (and therefore its QF rates) to be very similar to those of Duke Carolinas and Duke Progress.

Q. ARE THERE ADDITIONAL REASONS TO EXPECT ALL THREE UTILITIES TO HAVE SIMILAR COSTS AND QF RATES?

A. Yes. They operate in the Carolinas; they use many of the same technologies to generate electricity; they use many of the same suppliers; and they draw from the same general labor pool. Another reason to expect convergence of all three sets of QF rates is the presence of transmission connections between SCE&G and other utilities. Transmission ties make it feasible to transfer energy and capacity between SCE&G and nearby utilities, including Duke Carolinas, Duke Progress and Southern Company, enabling Duke or Southern Company to sell excess energy or capacity to SCE&G, or vice versa.

Q. WHY ARE THESE TRANSMISSION CONNECTIONS SIGNIFICANT?

A. They ensure that SCE&G is not required to always operate in isolation. Not all of the electricity produced in SCE&G's service area has to be consumed there, and vice versa. At least in theory, transmission paths can potentially be arranged for wheeling power to or from utilities located quite far away, including the Tennessee Valley Authority and utilities in the PJM region.

Given the multiplicity of different transmission paths that exist between various utilities, the circumstances in any given service area should not be viewed in complete isolation. For instance, if a shortage or surplus of power emerges in a given service area, market mechanisms can serve to alleviate the shortage or surplus, by moving power from areas where it less valuable (e.g. in surplus) to areas where it is more valuable (e.g. not in surplus).

To some degree electricity can be viewed as a fungible commodity which allows market mechanisms to mitigate against extreme discrepancies in the cost or value of electrical energy or capacity in neighboring areas. These types of market mechanisms help explain why prices for commodities like corn, wheat, milk, crude oil and gasoline frequently show a tendency to equilibrate toward uniformity across multiple markets, despite differences in local supply and demand conditions.

Q. ARE YOU SUGGESTING THAT WHOLESALE MARKETS KEEP THE PRICE OF ELECTRICITY PRECISELY THE SAME IN EVERY AREA?

A. No. The market for electricity is not perfectly competitive, so there is no reason to anticipate perfect uniformity in different areas. Utilities enjoy substantial monopoly power within their respective service areas, and there are transmission constraints and other impediments which introduce "friction" into the wholesale market. As a result, we can expect to observe discrepancies between the price at which sellers are willing to offer power and the price at which buyers are willing to purchase power at any given time.

Because of the line losses which occur when electricity is moved over long distances, and because of the administrative costs and difficulties involved with arranging the transmission paths to move energy or capacity from places where it is in surplus or cheap to produce, to places where it is needed or has a higher value, we can and do see moderate locational differences in prices that persist over time. However, extreme pricing differences are unlikely to persist for long. In general, the greater the discrepancy in prices, the greater the incentive to find ways to move power from low price areas to high price areas.

Although line losses, transmission capacity constraints and other complicating factors are important and need to be acknowledged, there is no reason to anticipate they are serious enough to perpetuate extreme pricing discrepancies like those shown in Tables One and Two above. To the contrary, it is reasonable to expect the wholesale price for capacity and energy in SCE&G's service area to be reasonably similar to that of neighboring utilities, particularly over the long run.

Q. SINCE COMPETITIVE PRESSURES DON'T FORCE UTILITIES TO PARTICIPATE IN WHOLESALE MARKETS, WHY WOULD YOU EXPECT PRICES TO EQUILIBRATE TOWARD UNIFORMITY?

A. State and Federal regulators expect utilities to make prudent efforts to minimize their costs, in order to impose as small a burden as possible on their captive customers. Consistent with the underlying purpose of utility regulation, utilities are expected to engage in the same sorts of efficiency-inducing behavior that is observed in competitive markets. Supply and demand imbalances in local markets for corn, wheat, milk, crude oil or gasoline are resolved in part by engaging in “win-win” market transactions that benefit areas experiencing unusually low prices as well as those experiencing unusually high prices.

Wholesale transactions can and do occur between neighboring utilities, and sometimes over longer distances, which benefit ratepayers on both sides of the transaction. For instance, if a utility unexpectedly sees a need for more capacity or energy, purchasing power may be faster, or more cost effective, than trying solve the problem by rushing to build new capacity. Similarly, if a utility experiences a temporary surplus of capacity or energy, selling power may be appropriate, if this will reduce the cost burden imposed on its customers, who will typically be paying the full cost of owning and operating the surplus capacity.

The optimal strategy could vary depending on the circumstances. It might involve selling a "slice" of the utility's system, or rights to the output from a specified generating unit, or a specified block of energy and/or capacity on a long term contractual basis. Or, it might involve using the excess capacity to generate electricity that is offered for sale in a market where prices are higher than the utility's variable cost of generation. In the latter case, the margin above variable costs helps offset at least some of the cost of owning the excess capacity. Regardless of the specific strategy, the idea is to reduce the burden on ratepayers who are paying for capacity in the utility's rate base that exceeds the amount needed to serve them.

PURPA

Q. BEFORE MOVING INTO YOUR ANALYSIS OF SCE&G'S PROPOSED QF RATES, CAN YOU PLEASE EXPLAIN YOUR UNDERSTANDING OF THE FEDERAL STANDARDS WHICH APPLY TO THESE RATES?

A. Yes. In 1978, Congress established a special class of generating facilities known as "Qualifying Facilities." [16 U.S.C. Sec. 824a-3] Under PURPA, electric utilities are required to purchase electrical energy from Qualifying Facilities ("QF's") at rates which must not discriminate against the firms that operate these facilities.

More specifically, PURPA requires the Federal Energy Regulatory Commission ("FERC") to prescribe rules necessary to "encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity." [Id., Sec. 824a-3(a)] State commissions have an important role in implementing PURPA, together with FERC and the courts.

> Questions about the actual avoided-cost determinations are litigated before the state commissions or the state courts with applicable jurisdiction for non-regulated utilities. Questions regarding whether a method of avoided-cost determination is consistent with PURPA and FERC implementation rules are litigated before FERC or an applicable federal court. [PURPA Title II Compliance Manual, Page 15}[1]

1 The PURPA Title II Compliance Manual was jointly published by the American Public Power Association (APPA), Edison Electric Institute (EEI), National Association of Regulatory Commissioners (NARUC) and National Rural Electricd Cooperative Association (NRECA) on March 2014, with the intended purpose of

State commissions have been provided with extensive guidance for how they are to carry out their responsibilities, both in the text of the underlying statute, and in rules adopted by FERC which were subsequently upheld by the United States Supreme Court.[2] For instance, rates for purchases from QF's ("QF rates") must: a) be just and reasonable to the electric consumers of the electric utility and in the public interest; b) not discriminate against qualifying cogenerators or qualifying small power producers; and c) cannot exceed "the incremental cost to the electric utility of alternative electric energy." [Id., Sec. 824a-3(a)]

While I am not an attorney, it is my understanding as an economist that under PURPA the Commission is expected to (1) require utilities to purchase energy and capacity from QF's on terms consistent with all applicable FERC regulations; (2) treat avoided costs as the pricing floor for those purchases; (3) enforce the legal right for QF's to sell power to utilities on either an as-available basis, or pursuant to a "Legally Enforceable Obligation" at the QF's option; (4) enforce the legal right for QF's to sell power to utilities pursuant to long-term contracts; (5) ensure utilities provide nondiscriminatory interconnection and/or transmission service to QF's that they sell power to QF's on request.

being used as an aid to state commissions and utilities as they deal with issues related to PURPA.

2 American Paper Institute, Inc. v. American Electric Power Service. Corp., 461 U.S. 402, 103 S.Ct. 1921 (1983).

Q. CAN YOU EXPLAIN THE "INDIFFERENCE" STANDARD AND THE "AVOIDED COST" CONCEPT?

A. Yes. As the FERC has stated on several occasions, the intention of Congress in enacting PURPA "was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly encouraged alternatives" of PURPA.[3] As explained more recently by the North Carolina Utilities Commission, "the goal is to make ratepayers indifferent between purchases of QF power versus construction and rate basing of utility-built resources."[4] Although PURPA is designed to encourage QF development, it does not accomplish this by subsidizing QF's, or by requiring customers to pay more for their power. To the contrary, if PURPA is correctly implemented, ratepayers are "held harmless," leaving them indifferent to whether they receive power from a QF or from new generating units added to the utility's rate base.

FERC recently confirmed that ratepayers should be "financially indifferent" when QF rates are appropriately set, and it went further by rejecting arguments that financial indifference must be narrowly defined, to exclude consideration of "societal and environmental benefits."[5] FERC concluded that states may take societal and environmental benefits into account in establishing prices that leave ratepayers

3 *Southern Cal. Edison, San Diego Gas & Elec.*, 71 FERC ¶ 61,269 at p. 62,080 (1995).

4 North Carolina Utilities Commission, December 31, 2014 Order Setting Avoided Cost Input Parameters, Docket No. E-100, Sub 140, Page 21.

5 FERC, Order Denying Rehearing, Docket No. EL 10-06-002, January 20, 2011, Paragraph 16.

indifferent: "We disagree with the arguments of the Joint Utilities and EEI that the guidance provided by the Commission is inconsistent with our avoided cost pricing rules and Congress's intent that utility customers be financially indifferent."[6]

The FERC rules implementing PURPA generally require electric utilities to purchase any energy and capacity which is made available to the utility from a Qualifying Facility. [18 CFR, Sec. 292.303(a)] Rates for purchases from Qualifying Facilities built after 1978 must be based upon the electric utility's "avoided costs." [Id., Sec. 292.101(b)] Although the term "avoided cost" is not used in the text of PURPA, it is consistent with the statutory language referencing the "incremental cost of alternative electric energy," which is defined in PURPA as: "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." [Id., 16 U.S.C. Sec. 824a-3(d)] More specifically, FERC defines avoided costs as:

> [T]he incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source. [Id., Sec. 292.101(b)(6)]

Among other things, the FERC rules require state commissions, to the extent practicable, to consider these factors when determining avoided costs:

> (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

6 Ibid, Paragraph 31.

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity. [Id., Sec. 292.304(e)]

Q. CAN YOU EXPLAIN WHAT INFORMATION IS REQUIRED BY SECTION 292.302(B) OF THE FEDERAL CODE OF REGULATIONS?

A. Yes. Under part C of Section 210 of PURPA, utilities like SCE&G are required not less often than every two years to provide to their state regulatory commission the following information, and to make it available for public inspection:

> (1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;
>
> (2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and
>
> (3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

SCE&G generally submits this information to the Commission in June of even-numbered years – most recently in June 2014 and June 2016.

Q. CAN YOU EXPLAIN YOUR UNDERSTANDING OF WHY THIS INFORMATION HAS TO BE PUBLICLY AVAILABLE, WHY THE "INDIFFERENCE" AND "AVOIDED COST" REQUIREMENTS WERE IMPOSED, AND WHAT THESE ASPECTS OF PURPA ACCOMPLISHED?

A. Yes. Looking at the relevant portions of PURPA from my perspective as an economist, it appears to advance at least two distinct goals: First, it encourages expanded use of targeted technologies and energy sources which had been neglected by the electric utility industry. Second, it encourages investment in small power producers – new firms that enter the market to develop these targeted technologies and energy sources.

With respect to the first goal, PURPA advanced an "all of the above" energy strategy, which was intended to encourage greater energy independence and increased supply diversity in the United States.

The scope of this portion of PURPA was narrowly focused. Utilities were exempted from any requirement to purchase from independent power producers that used the energy sources that had been historically been favored by electric utilities, like coal, residual oil, nuclear and natural gas. Instead, Congress focused on certain unconventional energy sources, like cogeneration, that had not been aggressively pursued by utilities. Cogeneration facilities are specialized installations that produce electric power in conjunction with another form of energy, like the production of heat or steam for use in a manufacturing process. Congress apparently was convinced this was a cost-effective and energy-efficient technology which had the potential for more widespread deployment than had been observed up to that time, in the absence of regulatory intervention.

Other targeted technologies include electricity produced from biomass and waste, as well as renewable resources like wind, small hydro, solar and geothermal energy. The primary purpose in encouraging investment in these specialized energy sources was similar to the reason why cogeneration was targeted: if PURPA was successful in encouraging new entry, supply diversity would be improved, and the country would reduce its dependence on scarce and nonrenewable resources like coal and oil.

Q. CAN YOU ELABORATE ON THE SECOND GOAL YOU MENTIONED – ENCOURAGING INVESTMENT BY SMALL POWER PRODUCERS?

A. Yes. By requiring utilities to purchase from QF's, Congress was not only encouraging diversity of energy supply sources, but it was also pursuing a strategy of encouraging competition in the electric power production. PURPA was adopted at a time when public policy makers were trying to scale back unnecessary regulations, improve regulatory structures, and rely more on competition to advance the public interest – particularly in industries, like the electric power industry, where competition had (intentionally or unintentionally) been effectively suppressed by government policy.

Perhaps the most memorable and visible example of this new approach was the deregulation of airlines which occurred around the same time. In this industry, safety continued to be tightly regulated, but other rules were changed to remove barriers to entry, encourage new airlines to challenge incumbent firms and to deregulate prices, which had previously been tightly controlled. The resulting increase in competition successfully unleashed a tidal wave of innovations, cost cutting, and price reductions.

Although PURPA was not as visible or dramatic, it reflected much the same pro-competitive philosophy underpinning airline deregulation. Congress sought to gain some of the benefits of increased competition without foregoing the benefits of traditional rate base regulation. The idea was to retain existing constraints on monopoly power in retail markets, while introducing new, carefully thought-through constraints on monopsony power in wholesale markets. The key to this strategy was encouraging increased investment and new entry by small, independent power producers, who had the potential to unleash downward pressures on the incumbents' costs and retail prices, without taking the risk of fully deregulating an industry which had many of the characteristics of a natural monopoly.

Thus, it is fair to say that one of the fundamental goals of this portion of PURPA was to encourage, on a narrowly targeted basis, increased competition in the market for electrical generation without jeopardizing continued regulation of other aspects of the industry. The strategy was straightforward: encourage investment in small firms that would use unconventional technologies to produce electricity in competition with the existing, vertically integrated electric utilities.

Q. WHY WAS THIS SORT OF ENCOURAGEMENT NEEDED?

A. Prior to the adoption of PURPA, most electric utilities obtained all, or nearly all, of their power from large centralized generating plants that they owned and constructed themselves, or from similar plants operated by a nearby utility. Congress made a conscious decision in 1978 to deviate from this historical pattern by encouraging investment in small power producers (80 MW or less at any single site) that would be entering the market in competition with the vertically integrated utilities, provided they focused on the targeted technologies.

Before PURPA, the monopoly power enjoyed by electric utilities in the transmission and distribution of electricity and the regulatory apparatus designed to constrain that monopoly power combined to discourage competition. This was true even for parts of the electric industry – like generation – which did not seem to exhibit the characteristics of a natural monopoly.

For example, before PURPA, few industrial firms would consider generating their own power, even where this would be economically efficient (e.g. utilizing waste heat from the manufacturing process), because there wasn't a ready market for power produced in excess of the firm's own needs. Practical constraints, as well as legal barriers associated with monopoly regulation, made it difficult or impossible for industrial firms to sell power to anyone other than the local utility, and most utilities weren't interested in buying power from new entrants. Rather, electric utilities generally preferred obtaining power from conventional generating plants – particularly ones they owned and operated themselves.

Before PURPA was adopted, the utility's preference for owning and operating its own generating plants using conventional energy sources nearly always prevailed over what might otherwise have been commercially viable transactions to purchase from independent power producers that would have ultimately benefited the utilities' customers. The utility was largely immune from pressures to pursue unfamiliar technologies or to buy from independent power producers, because it was effectively both a monopolist (single seller) and a monopsonist (single buyer), within its particular service territory.

Thus, for example, unless an industrial firm was willing to pull up stakes and move to another state, it was forced to pay whatever price the utility charged for whatever power it used, and it was forced to accept whatever price (typically much lower) the utility was willing to pay for any extra power the industrial firm produced. Before PURPA, if the gap between the price charged and the price paid seemed unduly large, an industrial firm could in theory complain to the state regulator about the magnitude of the gap, and ask the regulator to require the utility to pay a higher price, but in practice this option was generally too costly and risky to be worth pursuing. Accordingly, before PURPA, most industrial firms ignored the potential for cogeneration, regardless of how attractive the underlying economics might be, rather than risk undertaking an investment that would be subject to the utility's unconstrained monopsony power, or the uncertain outcome of future regulatory decisions.

This problem was not limited to cogeneration by industrial firms – it also affected the viability of investments in power production by small run-of-river hydro plants and other opportunities that existed for generating electrical power on a small scale. The utility was typically the sole buyer of power in the local market, and it controlled interconnection to the power grid, thereby largely determining the viability of small power production by other firms. Absent a well-defined system of constraints on the utility's monopsony power, small power production was an enormously risky proposition that few investors were willing to seriously contemplate.

Q. CAN YOU BRIEFLY ELABORATE ON THE DISTINCTION BETWEEN MONOPOLY POWER AND MONOPSONY POWER, AS IT RELATES TO THE HISTORY OF REGULATION?

A. Yes. By the early 1900's in most jurisdictions a comprehensive system of regulation to control monopoly power had evolved, which severely limited the ability of electric utilities to impose unreasonable prices, terms, and conditions on their sales transactions with most retail customers. In contrast, prior to the adoption of PURPA, relatively little thought was given to monopsony power, and in most jurisdictions no comparable comprehensive regulatory mechanisms existed to constrain the behavior of electric utilities in their dealings with independent power producers.

As the primary or exclusive potential buyer of electrical energy within their respective market areas, the incumbent electric utilities enjoyed as much "monopsony power" when buying electricity as the "monopoly power" they had when selling energy. Taking advantage of their market power, utilities generally decided to construct, own and operate their own generating units, or to purchase power from neighboring utilities, rather than buying from independent firms.

In general, incumbent utilities prevented, or at least discouraged, competitive entry by other firms, even in situations where those firms had a clear efficiency advantage (e.g. the ability to generate electricity less expensively, by taking advantage of waste heat involved in industrial processes), or they were willing to take greater risks in trying new, less familiar technologies.

Whether or not it was intentional, the result was that electric utilities prevented the consuming public from seeing the benefits of competition by independent power producers, who could potentially bring down costs and bring long term societal benefits by increasing supply source diversity, experimenting with innovative technologies, reducing costs, increasing efficiency, or accepting lower profit margins. In sum, the potential benefits from imposing regulatory constraints on monopsony power are conceptually similar to the reasons why the monopoly power of the incumbent utilities have long been constrained. However, the existence of monopsony power, and the benefits from constraining it, have not been as widely understood or effectively dealt with.

Q. CAN YOU PLEASE ELABORATE ON WHY UTILITIES RESIST COMPETITION AND PREFER THEIR OWN GENERATING FACILITIES?

A. There are multiple factors which help explain why electric utilities have historically resisted competitive entry. (1) There is a natural tendency for utility company management to want to retain maximum direct control over system reliability and other outcomes for which they are ultimately accountable. (2) Management operates within the context of a growth-oriented U.S. corporate culture, which favors expansion of a firm's staff, assets, income, and earnings per share. (3) Management is expected to maximize profits and value for its stockholders, which leads to a strong bias in favor of expanding the rate base, due to the Averch-Johnson effect.[7]

7 Named after the authors of a famous article published in 1962 in the American Economic Review, which demonstrated that under typical conditions, rational rate base regulated firms will tend to expand their capital investment beyond the optimal point of maximum economic efficiency. This tendency occurs whenever the allowed rate of return exceeds the utility's actual cost of capital by even a small margin. Theoretically the Averch-Johnson effect could be avoided if the allowed rate of return were set precisely equal to the cost of capital. However, this degree of precision isn't achievable in practice. As well, an allowed return which exceeds a barebones estimate of the cost of capital can be viewed as preferable, since it helps maintain the utility's financial integrity, strengthens its financial ratios and protects its bond rating.

With PURPA, Congress attempted to overcome this resistance by reducing barriers to competitive entry into the electric utility industry without disrupting the more successful aspects of traditional rate base regulation. It did this by providing an overarching federal regulatory structure for implementing state regulatory oversight of transactions between electric utilities and QF's, with a view toward encouraging QF investment.

However, PURPA did not change the attitudes or preferences of the incumbent utilities. These firms continue to prefer owning and operating their own generating resources for perfectly rational reasons. If the benefits of competitive entry are going to fully emerge, it is necessary for state and federal regulators to actively implement the provisions of PURPA in a way that fulfills the goal of encouraging competitive entry, and placing greater reliance on market forces to advance the interests of ratepayers and the public good.

Q. HAVE UTILITIES CONTINUED TO RESIST COMPETITIVE ENTRY INTO POWER PRODUCTION, DESPITE THE REQUIREMENTS OF PURPA?

A. Yes. In my experience, utility companies have consistently advocated proposals that have tended to discourage QF investment and justified continued expansion of their own rate base instead. While continued resistance to competitive entry is readily predicted and explained as a matter of economic theory, it's important to realize this is not a merely speculative or theoretical concern, but a fundamental aspect of the industry.

It is helpful for regulators to understand and recognize this aspect of the industry in deciding how to interpret and implement the various provisions of PURPA. Succinctly stated, in a typical retail rate proceeding, the utility will often seek rates that are higher than necessary or appropriate, but in a QF rate proceeding the reverse is true: the utility will often seek rates that are lower than necessary or appropriate. The Commission should keep this in mind, and try to strike an appropriate balance which serves the long-run best interests of the consuming public in South Carolina.

The historical record is filled with evidence that confirms the industry's preference for low QF rates, its resistance to QF investment, and its preference for putting generating units into their rate base rather than purchasing power from independent power producers. For example, the industry opposed FERC's rules implementing PURPA, arguing that it was inappropriate to require them to pay QF rates that were equal to their full avoided cost. Utilities fought this battle all the way to the U.S. Supreme Court, which unanimously rejected their arguments, concluding that FERC had not acted arbitrarily or capriciously in requiring utilities to buy QF energy at rates equal to full avoided cost.[8] The Court recognized this would not directly provide any rate savings to consumers, but it accepted FERC's reasoning that it was more important to provide a significant incentive for the development of cogeneration and small power production, and that ratepayers and the nation as a whole will benefit from decreased reliance on

8 American Paper Institute, Inc. v. American Electric Power Service Corp., 103 S.Ct. 1921 (1983)

scarce fossil fuels and increased efficiency. Since that time, utilities have generally been more circumspect in their efforts to discourage QF development in preference for investing in their own facilities, but they have continued to do so.

Q. CAN YOU ELABORATE ON HOW UTILITIES FAVOR INCREASES TO THEIR RATE BASE RATHER THAN QF INVESTMENT?

A. Yes. For instance, they have sometimes been slow to negotiate with developers, creating delays and making it more costly and difficult to get a project off the ground. Similarly, utilities often insist on QF contracts with much shorter durations than they themselves use when building and financing projects with other utilities. They also seek to impose terms and conditions in contract negotiations that make it more difficult to obtain financing for QF projects. In order to finance a project, QF's will typically need to have already signed a long-term purchase power agreement at fixed or pre-specified prices. Those prices and other terms of the contract are crucial in determining whether banks and other investors will invest the capital needed to complete a project.

Utilities also tend to develop low estimates of their avoided costs and they often adopt tactics which have the effect of discouraging investment by small power producers. Specific examples include: (1) adopting a narrow view of what costs can be avoided; (2) shielding their avoided cost calculations from public disclosure, making it more difficult for potential entrants to evaluate investment risks and opportunities in a given state, and making it harder for regulators to draw comparisons with calculations developed in other jurisdictions; (3) using lower, more optimistic fuel price forecasts to estimate avoided costs than the ones used to evaluate their own generating expansion plans; (4) putting their own generating sources at the "front of the line" by treating their own plans as higher priority, or a "given" while treating potential QF investment as unnecessary, given that they already have a plan for meeting future needs; (5) effectively discriminating against QF generators by not providing them with an equivalent level of compensation as they receive when new plants are added to their rate base; (6) developing QF rates using inconsistent and/or biased assumptions that are skewed against the QF; and (7) resisting proposals to improve the precision and sophistication of the tariff development process, if the effect of those proposals might be to encourage more QF investments.

Unfortunately, utilities' QF rate filings don't always receive the same level of scrutiny as retail rate proposals. There are many possible explanations for this, including the fact that the issues are sometimes unfamiliar, and they arise in the context of highly specialized tariff filings which have an immediate, direct effect on very few people. In fact, unless and until independent power producers actually enter a given state market to compete with the utilities, there may not be anyone in the state for whom accurate QF rates is a top priority, or who can justify expending the effort required to intervene into the regulatory process in order to challenge the utility's QF rate calculations. Since QF entry generally occurs after tariffed rates are established, a "chicken and egg" phenomenon can arise, in which no one enters the market, and no one is willing to expend the effort required to advocate the sorts of changes that would make QF entry more feasible.

Q. DO RETAIL CUSTOMERS BENEFIT FROM SETTING QF RATES AT ARTIFICIALLY LOW LEVELS?

A. No. Although low QF rates may be superficially appealing (on the assumption that lower QF rates will translate into lower retail rates through a fuel adjustment and purchased power mechanism), artificially suppressing QF rates does not benefit ratepayers. Any short term benefit from low QF rates is of limited value, because low QF rates discourage QF investment, thereby reducing the amount of energy that the utility will actually obtain at the lower rates. Taken to the extreme, if QF rates are so low that no QF investment occurs, no purchases will be made at the low rates, and there will be no savings available to flow through to retail customers.

Even if some QF developers end up selling some power at an artificially low rate (e.g. they are already committed to their projects before the low rates are established), the potential benefit to retail customers will be limited, because future QF investment will be discouraged and the potential for increased pressure on the utility to operate efficiently will be lost. Instead, customers will be forced to buy more costly power generated by the utility itself. Simply stated, over the long run, retail customers are harmed by low QF rates, because low rates shield utilities from competition, reducing pressures for them to minimize their costs.

Furthermore, low QF rates encourage unnecessary expansion of the regulated rate base, thereby shifting risks onto retail customers that could have been borne by QF investors instead. For example, when generating plants are built by utilities, customers bear nearly all of the risks associated with scheduled delays and construction cost overruns. Absent an extraordinary finding of imprudence, which rarely occurs, all of the risks associated with construction are ultimately borne by ratepayers. Even in cases where a plant is retired early, or construction is never completed, ratepayers will normally shoulder the burden of any resulting stranded costs.

In contrast, when independent power producers build plants, customers are shielded from these risks, because they only pay for power that is actually generated, and the price remains the same regardless of what delays or cost over-runs occur during construction. In sum, it is not in the public interest for the Commission to endorse unrealistically low avoided cost estimates, or to adopt low QF Rates. To the contrary, the public interest is best served by encouraging competition, by accurately and fairly implementing the provisions of PURPA and the associated FERC rules.

Q. ARE YOU ADVOCATING SETTING QF RATES AT THE HIGHEST ALLOWABLE LEVEL?

A. No. A middle course is preferable. Retail customers are better served by regulatory decisions that set QF rates away from these extremes, at a point that is closer to the long run incremental costs that are incurred by utilities when they build and operate their own generating plants. I believe this long-run incremental cost standard is also more consistent with the requirements of federal law. It encourages competitive entry by small power producers, without imposing a cost burden on customers, and without subsidizing QF development or running the risk of encouraging economically inefficient levels of QF investment.

Stated a little differently, the public interest is best achieved by establishing rates that leave ratepayers indifferent as to whether energy and capacity is obtained from QF's or from the utility itself under traditional rate base regulation. By setting QF rates equal to the cost of having the utility build and operate its own generating units, PURPA creates a level competitive playing field between utility-owned generation and QF power purchases. This encourages investment by QF developers to the extent they believe they can operate more efficiently or at lower cost, or they are more willing to experiment with new technologies, or they are willing to accept a lower return on their investment than the one paid on comparable investments put into the utility's rate base. This creates healthy competition, which exerts downward pressures on retail rates, pressures the incumbent utilities to minimize their own costs, and benefits retail customers over the long term.

Q. IN DEVELOPING QF RATES, SHOULD COSTS BE EVALUATED ON A SHORT-TERM BASIS?

A. No. I believe the purpose of PURPA can best be accomplished by taking a long-term view of the choice between QF and utility-provided power. More specifically, I believe the concept of "indifference" and the calculation of avoided costs should generally be consistent with the full incremental cost of building and operating generating facilities over their entire economic life cycle.

In the electric utility industry, short-run costs are sometimes less than long-run costs, due to lumpiness of capital additions among other factors. However, ratepayer are required to bear the full long-run cost of plants that are put into the rate base. If QF rates only considered a short-run measure of costs, like variable operating costs, while ignoring other costs the utilities incur (and customers pay) in the long run, a mismatch occurs, and indifference is not achieved. Stated another way, using a short-run view of avoided costs that fails to consider the full cost of building and operating new generating plants over their economic life cycle will discriminate against QF's and discourage QF investment.

Accordingly, it has often been recognized that the appropriate measure of avoided costs is one that is equivalent to the total costs incurred when a utility builds, owns and operates new generating plants over their life cycle. Properly implemented, a long-run measure of costs ensures that QF's receive the same amount for their power as the utilities receive for power produced using their own generating plants – no more and no less.

It should also be noted that QF's typically sign long-term contracts to sell their output at "fixed or pre-specified prices" and this is type of contract is needed for them to obtain debt financing. For logical consistency, long-term contracts generally require the use of "long-term estimates of avoided cost."[9] Furthermore, FERC has clarified that under PURPA QF's are entitled to sell electricity pursuant long-term contracts with forecasted avoided cost rates.[10]

Avoided Cost Methodologies

Q. HOW ARE "AVOIDED COSTS" ESTIMATED?

A. There are three major methods that have been used to develop avoided cost estimates, including (1) the Proxy Unit method (also sometimes referred to as the Proxy Resource or Committed Unit method), (2) the Differential Revenue Requirement (DRR) method, and (3) the Peaker method.[11] The Commission has accepted the use of both the DRR and

9 Edison Electric Institute, PURPA: Making the Sequel Better than the Original, December 2006, Page 9.

10 Hydrodynamics Inc., 146 FERC ¶ 61,193 (Mar. 20, 2014) at P 34; 18 C.F.R. Sec. 292.304(d)(2).

11 PURPA: Making the Sequel Better than the Original, page 9. See also the PURPA Title II Compliance Manual, page 35 and Reviving PURPA's Purpose, Carolyn Elefant, Page 13

Peaker methods (SCE&G uses the DRR method and Duke uses the Peaker method) but there is no inherent inconsistency in doing this. To the contrary, all three of these methods are intended to measure the same thing (long run incremental costs), so all three methods can (and should) yield approximately the same total cost per kWh under normal circumstances (assuming each one is properly performed using similar inputs and assumptions).

Q. CAN YOU BRIEFLY EXPLAIN THE PROXY UNIT METHOD?

A. Yes. The Proxy Unit (or Proxy Resource) method is described in the PURPA Title II Compliance Manual as follows:

> This method bases the avoided cost on the cost of the host utility's next planned addition, typically a combined cycle/gas turbine (CCGT) generating unit. This approach essentially assumes that the QF substitutes for a planned utility generating unit, or what is assumed to be the next generating unit. The proxy unit's estimated fixed cost (annualized over the expected life of the unit) determines the avoided capacity cost and the estimated variable cost sets the avoided energy cost. The type and size of the unit or units is determined in an Integrated Resource Process (IRP) or from the utility's planning process, where the planning process, for regulated utilities, follows a state commission-approved procedure. Because this is a relatively simple method to use, the proxy method is very common, although the results largely depend on the type of unit or units chosen as the proxy.[12]

This methodology has many advantages, including the fact that it is relatively straightforward and easily understood. Its flexibility is also an advantage: It can be

12 PURPA Title II Compliance Manual, page 35.

implemented using data for a generating unit that is currently under construction, or has recently been constructed by the utility, a unit that has been identified for future construction in the utility's Integrated Resource Plan, a hypothetical or surrogate unit, or some combination or variant of these data sources. Later in my testimony I will be using the Proxy Unit method to provide an independent assessment of SCE&G's avoided costs, for comparison with the Company's proposed QF rates.

Q. ARE YOU ASKING THE COMMISSION TO ADOPT THE THE PROXY UNIT METHOD IN LIEU OF THE DRR OR PEAKER METHODS?

A. No, not at all. All three of these methods are intended to measure the same thing, and the choice of a specific method in a specific context is largely a matter of administrative or calculational convenience. It should not have any significant impact on the conclusions that are reached – assuming consistent assumptions and inputs are used in each instance.

In this instance, it was convenient to use the Proxy Unit method to develop some benchmark cost estimates for presentation to the Commission and to clarify some of the points I make in my testimony. The Proxy Unit method was ideal for this purpose because: (1) It is a relatively straightforward, simple method which is relatively easy to explain, implement and understand. (2) It can be developed using publicly available information, thereby improving transparency and reliability. (3) It is well suited for consideration of the information that must be provided by utilities pursuant to 18 C.F.R.

Section 292.302(b) as I mentioned earlier in my testimony.[13] This is significant, since the FERC rules specifically require state regulators to consider this information in setting avoided-cost based rates, to the extent practicable.[14] Moreover, this avoided cost data is available for many different utilities, potentially facilitating comparisons with data submitted by other utilities. (4) It offers great flexibility, which made it easier to develop multiple different calculations using a wide variety of different assumptions (e.g. fuel choices and cost scenarios). However, none of the conclusions I reach are contingent on the use of the Proxy Unit method, nor am I suggesting the Company, or the Commission, should switch to the Proxy Unit method.

Q. CAN YOU BRIEFLY EXPLAIN THE DIFFERENTIAL REVENUE REQUIREMENT METHOD?

A. Yes. The DRR method is described in the PURPA Title II Compliance Manual as follows:

> Under a revenue requirement differential method, the system revenue requirement without the QF is subtracted from the system revenue requirement with the QF.[15]

13 All of the information submitted by utilities pursuant to this regulation tends to be useful, including the cost of planned capacity additions and firm purchases on the basis of dollars per kilowatt, and the associated costs of each unit, expressed in cents per kilowatt hour. In SCE&G's case, this submission includes the cost of its planned VC Summer nuclear generating plants, which provides a useful point of reference for comparison with the proposed QF rates.

14 Section 292.304(e) CFR

15 PURPA Title II Compliance Manual, page 35.

The DRR method, as typically discussed, is a fairly complex approach, requiring the use of two different computer models.

> A planning expansion model is used to develop generation expansion plans both with and without the estimated QF output. The resulting two expansion plans then are used as inputs to a financial planning model that yields the utility's projected revenue requirement both with and without the QF output (assuming that the QFs are a "free" resource). The difference in the present value revenue requirements of these two expansion plans is the avoided revenue requirement made possible by the expected QF output. This avoided revenue requirement includes avoided energy and capacity costs as well as other factors (e.g., taxes)[16]

SCE&G's witness, Mr. Lynch, explains that his avoided energy and capacity cost calculations were developed using a "difference in revenue requirements methodology"[17]

> The base case is defined by SCE&G's existing fleet of generators and the hourly load profile to be supplied by these generators. The change case is the same as the base case except that the hourly loads are reduced by 100 megawatts ("MW") in each hour...
>
> The avoided costs are then calculated by taking the difference in revenue requirements between the two plans.

As is typical of the DRR method, SCE&G compares two different scenarios. It's avoided cost estimates are based on the computed difference between these scenarios. However, the Company's approach is simplified, because it does not develop a comprehensive, detailed analysis of its revenue requirement under the two plans (either scenario).

16 PURPA: Making the Sequel Better than the Original, December 2006, Page 11.
17 Direct Testimony of Joseph M. Lynch, page 4.

Mr. Lynch testified in the prior rate proceeding (Docket No. 2016-2-E) that SCE&G "uses a resource optimization planning model to calculate the present worth of revenue requirement under base case assumptions and under a change case."[18] However, after examining the company's work papers, I've concluded they did not adequately achieve resource optimization, nor did they adequately analyze changes to the revenue requirement which would occur in a real life scenario matching the "change case." Accordingly, I have concluded that the Company's implementation of the DRR method is flawed.

The Company was asked in discovery to produce "Copies of all work papers and source documents, utilized or relied upon in formulating SCE&G's request for a new PR-2 Rate." In response it provided two workpapers, neither of which computes its rate base or develops operating expenses, revenues, and miscellaneous sources of income in a manner that is equivalent to the way its revenue requirements would be developed in a retail rate case. Instead, it adopts simplifying assumptions and inputs which, as I will explain later in my testimony, have a significant downward impact on its cost estimates.

The energy portion of its calculations are the most detailed; they were developed using a proprietary computerized production cost model called Prosym. Unfortunately, the Company didn't provide its detailed Prosym inputs and assumptions with its testimony, nor in its initial response to discovery. Furthermore, it didn't use the full power of

18 Order No. 2016-297, Page 16.

computer modeling to analyze its revenue requirements in detail under a full range of relevant planning and optimization scenarios. Significantly, it used simplified assumptions and inputs which excluded consideration of strategies it could use to minimize its revenue requirement – strategies that could vary, and have different implications for the DRR results, depending on the assumed circumstances. These simplifications are important in this case, because they influenced the conclusions the Company reached when comparing the revenue requirement in the scenario with the extra 100 MW of "free" QF power compared to the analogous scenario without this power. I will discuss this in more detail later.

Q. CAN YOU BRIEFLY EXPLAIN THE PEAKER METHOD?

A. This is the method which Duke has historically used in both South and North Carolina. The Peaker Method is described in the PURPA Title II Compliance Manual as follows:

> Under the peaker method, the value of the QF's capacity is determined by assuming that the QF will be operating as a utility peaking unit. If the utility requires capacity, this method sets the avoided capacity at the lowest-cost capacity option available to the utility, for example, a combustion turbine (CT). Avoided energy cost may be based on the utility's system-wide avoided energy cost, not the peaking unit's energy cost. This requires production cost modeling to determine the system-wide avoided energy cost, which increases the complexity of this method over the "proxy" unit approach.[19]

19 PURPA Title II Compliance Manual, page 35.

The Peaker method has at least one significant advantage: it develops energy cost estimates on an hour-by-hour, year-by-year basis. However, some of this advantage can be lost when the calculations are averaged and levelized across broad, potentially arbitrary "Peak" and "Non-Peak" categories and seasons (groups of months). The Peaker Method also has at least one significant disadvantage: it is not especially well-suited to fully utilize the information provided pursuant to 18 CFR Section 292.302(b), particularly with regard to the incremental cost of nuclear and other baseload generating units, since this data isn't used in the Peaker Method.

Q. DO ALL THREE METHODS ESTIMATE THE INCREMENTAL COST OF BUILDING AND OPERATING NEW GENERATING FACILITIES OVER THEIR ECONOMIC LIFE CYCLE?

A. They can, and in my opinion they should. Incremental life cycle cost is an appropriate benchmark, which can be estimated using any of these methods, if they are correctly implemented with appropriate assumptions and inputs.

It is easiest to see this with the Proxy Unit method, which specifically focuses on the life cycle cost of owning and operating a specific unit. Like any method, however, the costs that are calculated will vary – particularly on a per kWh basis – depending on the assumptions and inputs which are selected, and how they are used. For instance, if avoided costs are being calculated for use in paying QF's for power that will be generated during many hours of the year, the primary focus should be on a proxy unit that is cost-effective in serving long duration loads, like a Combined Cycle or Nuclear unit. If the analysis were limited to a peaking unit instead, the resulting cost per kWh could be higher than the full life cycle cost of owning and operating a baseload plant, because a combustion turbine has very high fuel costs, which outweigh its low construction costs if power is going to be provided during many hours of a typical day.

In the case of the Differential Revenue Requirement method, the opposite problem can arise, depending on what inputs and assumptions are used. For instance, appropriate inputs and assumptions ought to be used, to ensure the revenue requirement in each scenario is appropriately minimized – the same way the Commission makes sure that an excessive revenue requirement is not used when setting retail rates.

These inputs and assumptions should be adapted depending on the circumstances, to ensure that the revenue requirement is minimized under each scenario. For instance, in the "change" scenario which includes a "free" block of 100 MW of power provided by a QF, appropriate inputs and assumptions should be used to recognize the full long-run benefit of having this block of power available. If inappropriate or overly simplified inputs or assumptions are used, there may appear to be little difference between the two scenarios, and thus the value of the "free" block of power may be underestimated. When the revenue requirements in both scenarios are correctly analyzed, comparing two optimal long-run scenarios should reveal the true economic value of the power provided by the QF, which should be similar to the full cost of building and operating generating units capable of providing a block of 100 MW of power during every hour of every day.

The Peaker Method will also achieve this benchmark when appropriately implemented, although it isn't intuitively obvious how it can accomplish this, since it focuses on the capital cost of a peaker (combustion turbine or CT) rather than a base load plant like the VC Summer units that SCE&G is constructing, and a CT costs less per kW than a baseload unit. However, according to the theory underpinning the Peaker Method, assuming appropriate assumptions are used in running the production cost model (e.g. Prosym), the marginal running costs of the system (output from the model) should exceed the running costs of a new baseload plant by just enough margin to compensate for the added cost of the baseload plant, relative to the cost of a new peaking unit.

> According to the theory underlying the Peaker Method, if the utility's generating system is operating at equilibrium (i.e., at the optimal point), the cost of a peaker (combustion turbine or CT) plus the marginal running costs of the system will produce the utility's avoided cost. It will also equal the avoided cost of a baseload plant, despite the fact that the capital costs of a peaker are less than those of a baseload plant. This is because the lower capital costs of the CT are offset by the fuel and other operation and maintenance expenses included in system marginal running costs, which are higher for a peaker than for a new baseload plant. Thus, the summation of the peaker capital costs plus the system marginal running costs will theoretically match the cost per kWh of a new baseload plant, assuming the system is operating at the optimum point. Stated simply, the fuel savings of a baseload plant will offset its higher capital costs, producing a net cost equal to the capital costs of a peaker.[20]

20 North Carolina Utilities Commission, Order Establishing Standard Rates and Contract Terms for

Although it isn't intuitively obvious, this is fundamental to the theory underlying the Peaker Method, which assumes combustion turbines with poor heat rates will be operated at the top of the dispatch stack during enough hours of the year to ensure that the difference in fuel costs (e.g. between a new peaking unit and a new nuclear generating unit) will compensate for the additional capital costs of the baseload unit.

Stated another way, the Peaker Method doesn't provide recovery of the high fixed costs of a baseload plant like a Combined Cycle unit or nuclear plant in the avoided capacity cost results. Instead, the capacity costs are limited to those of a CT, while the remainder of the fixed costs of owning and operating a baseload plant are supposed to show up in the energy costs. The avoided energy costs are based upon the "top of the stack" (typically, the least fuel-efficient generating unit that is running during any given hour), which are expected to exceed the cost of fuel for baseload units by an amount that should be large enough to recover the portion of the baseload plant investment that exceeds the investment in a peaking unit.

Q. CAN YOU BRIEFLY HIGHLIGHT SOME PRACTICAL ISSUES WITH RESPECT TO PRODUCTION COST MODELS, LIKE PROSYM?

A. Yes. Both Duke and the Company rely on computerized production cost modeling to estimate their avoided energy costs on an hour-by-hour, year-by-year basis The great

Qualifying Facilities, Docket No. E-100, Sub 100, September 29, 2005, Page 17.

advantage of these models is that they produce cost estimates in extreme granular detail (literally 8,760 different cost numbers are generated for each year), and they can easily accomplish this level of granular detail for many different scenarios – simply by adjusting the inputs used in running the model for each scenario. For instance, a production cost model can easily develop precise estimates of how costs will be affected during various time periods and seasons, depending on what happens to fuel prices in future years. Similarly, it can provide this sort of highly granular cost information for scenarios reflecting other uncertainties, like the timing of when the VC Summer nuclear units will be completed, or how much the Company's energy costs (and retail rates) could be reduced if some of the excess energy that becomes available when these units are finished were to be sold to other utilities.

Unfortunately, the Company did not provide the detailed, hourly Prosym output with its testimony in this proceeding, nor did it provide this information in its initial response to our discovery requests. Instead, it summarized or aggregated this data across various time periods. This reduces or eliminates some of the potential benefits of using Prosym to develop energy costs on a detailed, hour-by-hour, year-by-year basis. Similarly, the Company didn't take advantage of Prosym's inherent "What if" capabilities to provide the Commission and other interested parties with energy cost estimates under multiple different scenarios (e.g. higher or lower fuel prices in future years).

This highlights one of the most significant disadvantages of using a production cost model: they are data-intensive and costly to license. Furthermore, extensive training is required before these models can be operated reliably. Because of these licensing and training barriers, the model effectively becomes a "black box" which cannot easily be penetrated by the Commission, ORS or other parties. Due to licensing and other barriers, it is difficult or impractical for other parties to probe the underlying inputs and assumptions that drive the avoided energy cost estimates produced by a model like Prosym. This is a significant consideration, since the inputs largely control the outputs of these types of computer models.

Avoided Capacity Costs

Q. HAVE YOU DEVELOPED ESTIMATES OF THE COMPANY'S AVOIDED CAPACITY COSTS?

A. Yes. I developed some benchmark avoided capacity cost estimates using the Proxy Unit method. The first estimate is based on a hypothetical nuclear plant, similar to the VC Summer project. The second estimate is based on a hypothetical Combined Cycle plant. The third estimate is based on a hypothetical Combustion Turbine.

Q. BEFORE DISCUSSING YOUR COST ESTIMATES IN DETAIL, CAN YOU BRIEFLY SUMMARIZE YOUR CONCLUSIONS REGARDING THE COMPANY'S AVOIDED CAPACITY COSTS?

A. Yes. These benchmark calculations suggest SCE&G's proposed rates are well below the capacity-related cost of building and operating any of these three types of generating units over their entire economic life. Together with the comparison to Duke's rates, discussed earlier, my benchmark avoided cost estimates suggest SCE&G's proposed QF rates are lower than optimal, and it would be appropriate for the Commission to increase the QF rates to be closer to Duke's rates – rather than lowering them, as the Company has proposed.

Higher QF prices would be more consistent with the long run incremental cost of new capacity, and would better encourage QF development within SCE&G's service area, which would be consistent with the intent of PURPA and FERC's rules, would help lower retail rates over the long run, and help advance the public interest.

Q. CAN YOU BRIEFLY EXPLAIN HOW YOU ESTIMATED THE COST OF CONSTRUCTION FOR A NEW NUCLEAR GENERATING UNIT?

A. In my avoided cost analysis I assumed an installed cost of $5,350 per kW for a newly constructed nuclear unit. I developed this number by looking at publicly available information concerning construction costs, including the cost of the VC Summer nuclear plants which SCE&G currently has under construction.[21] I started with the $7.6 billion cost estimate for the VC Summer units, which was provided in the Company's June 2016 PURPA filing. However, I recognized that the actual cost of construction will not be known until the units are completed. (The analogous estimate in the 2014 PURPA filing was $5.76 Billion.) Also, I recognize there is a learning curve involved with nuclear units, and thus future units might be less costly than the ones that are currently under development. Hence, I also considered the most recent available cost estimate published by the Energy Information Administration ("EIA") for new nuclear construction, which I adjusted to 2017 dollars using an annual inflation rate of 2.0% and to reflect local cost conditions using their state-specific cost adjustment factor:

Nuclear	Cost per KW in 2017 Dollars
Proxy Unit	**$ 5,350**
EIA – Advanced Nuclear [22]	$ 5,652
SCE&G – Summer June 2016 Estimate	$ 5,307

21 The Company's June 30, 2016 avoided cost filing in compliance with Subpart C, Section 210 of PURPA indicates the Company's next planned generating unit is VC Summer #2, which is projected to add 625 MW of capacity in 2020, 22 MW of capacity in 2021, and 23 MW in 2022. VC Summer #3 is expected to add 648 MW of additional nuclear capacity in 2021 and another 22 MW of capacity in 2022, for a grand total of 1,340 MW.

22 See Capital Cost Estimates for Utility Scale Electricity Generating Plants, November 2016 ("2016 EIA Report"), Page 7. Our calculations apply EIA's 4.9% location adjustment factor for South Carolina (Page A-20) and adjust for inflation at 2% per year.

Q. HOW DID YOU ESTIMATE THE COST OF BUILDING A NEW COMBINED CYCLE UNIT?

A. I started with an installed cost per KW in 2017 dollars of $1,050. This is consistent with these publicly available data sources:

	Combined Cycle	Cost per KW in 2017 Dollars
4	Proxy Unit	**$ 1,050**
5	EIA – Advanced CC[23]	$ 1,126
6	Duke – Dan River CC[24]	$ 1,007
7	Duke – Buck CC[25]	$ 1,060
8	Brattle – Dominion [26]	$ 1,041

23 See 2016 EIA Report, Page 7. We applied the EIA's -10.4% location adjustment factor for South Carolina (Page A-14) and adjusted for inflation.

24 Duke completed its Dan River Combined Cycle plant in 2012. According to DEC's 2014 FERC Form 1, the cost per KW of installed capacity was $912, which is equivalent to approximately $1,077 in 2017 dollars.

25 Duke completed its Buck Combined Cycle plant in 2011. According to DEC's 2014 FERC Form 1, the cost per KW of installed capacity was $941 per KW, which is equivalent to approximately $1,060 per KW in 2017 dollars.

26 See The Brattle Group and Sargent & Lundy, Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, May 2014 ("Brattle Report"), Page 43.

Q. HOW DID YOU ESTIMATE THE COST OF BUILDING A NEW COMBUSTION TURBINE?

A. I used an installed cost of $650 per KW in 2017. This is primarily based upon the most recent cost information published by the Energy Information Administration, but I also considered other publicly available data sources:

Combustion Turbine	Cost per KW in 2017 Dollars
Proxy Unit	**$ 650**
EIA – Advanced CT [27]	$ 645
Brattle – Dominion [28]	$ 885
Pasteris SOM – EMACC [29]	$ 763
SCE&G – 2023 CT [30]	$ 734

Q. HOW DID YOU TRANSLATE THE INSTALLED COST INTO ANNUAL EQUIVALENTS?

A. First, I added an allowance for the cost of construction financing. I then developed an allowance for depreciation based on an economic life of 30 years for the combined cycle

27 See EIA Report, Page 7. We applied the EIA's 6.8% location cost adjustment factor for South Carolina (Page A-18) and adjusted for inflation.

28 Brattle's estimate of the overnight cost of constructing an Advanced Combustion Turbine in Dominion's service area was $931 per KW in 2018/19. (Brattle Report, Page 41.)

29 See Brattle CONE CT Revenue Requirements Review, July 25, 2014, Page 12.

30 SCE&G June 30, 2014 PURPA avoided cost filing.

and combustion turbine units, and 70 years for the nuclear unit. I developed an estimate of income taxes using a composite state and federal tax rate of 34.93%, and I applied a weighted cost of capital of 7.36% (a pre-tax cost of capital of 10.17%), consistent with the following calculations:

Capital Source	Ratio	Cost Rate	Weighted Cost	Tax Factor	Pre-Tax Weighted Cost
Equity	50.00%	9.50%	4.75%	1.5367	7.30%
Debt	50.00%	4.75%	2.38%	1.0000	2.38%
Total	100.00%		7.36%		9.67%

The costs were initially developed for each individual year, then levelized across the entire economic life of the plant. The latter step is similar to the way most home mortgages are structured to provide uniform, level payments, even though the cost of the mortgage (the interest) varies from year to year. The end result was a uniform levelized capital cost of $490.75 per kW per year for the nuclear plant, $113.04 per kW per year for the combined cycle plant and $69.97 per kW per year for the combustion turbine.

Q. DID YOU CONSIDER ANY OTHER FIXED ANNUAL COSTS?

A. Yes. Before converting these levelized amounts into per-kWh costs, it was necessary to add an allowance for fixed O&M and corporate overhead costs. I assumed annual Fixed Operating & Maintenance expenses would be $95.00 per kW for the Nuclear plant, $10.00 per kW for the Combined Cycle Plant and $7.00 per kW for the Advanced

Combustion Turbine (in 2016 dollars). The assumptions are consistent with estimates developed by the Energy Information Administration and data from various utilities, which I have reviewed in the course of my consulting work. Applying an annual inflation factor of 2% and levelizing each figure results in an annual cost per kW in 2017 of $136.00, $12.64 and $8.85, respectively.

I also applied a 95% availability factor, to compensate for forced outages and times when the unit is unavailable for energy production due to scheduled maintenance (and refueling in the case of a nuclear unit). An allowance for corporate overhead costs was also needed; I provided a 5% allowance for this category of costs. All of these costs were developed on a year-by-year basis, then uniformly spread across the economic life of the plant. The resulting levelized costs totaled $692.72 per kW for the nuclear plant, $138.90 per kW for the combined cycle plant and $87.12 per kW for the combustion turbine.

Avoided Energy Costs

Q. HAVE YOU DEVELOPED ESTIMATES OF THE COMPANY'S AVOIDED ENERGY COSTS?

A. Yes. I also developed benchmark avoided energy cost estimates using the Proxy Unit method. The first estimate is based on a hypothetical nuclear plant, similar to the VC Summer project. The second estimate is based on a hypothetical Combined Cycle plant. The third estimate is based on a hypothetical Combustion Turbine.

When thinking about energy costs, maintenance, fuel and other operating costs that vary with energy output are what immediately come to mind. However, it's important to note that my energy-related cost estimates also include certain fixed capital-related costs. In order to arrive at an accurate distinction between costs that are attributable to the need for capacity during peak hours and costs that are energy related, it is necessary to recognize that some of the costs of building and owning a generating unit may actually be energy-related. Thus, the distinction between capacity-related costs and energy-related costs is not identical to the distinction between fixed costs and variable costs, nor is it identical to the distinction between capital-related and operating expense-related costs.

Q. HOW DID YOU SPLIT FIXED COSTS BETWEEN THE ENERGY AND CAPACITY RELATED CATEGORIES?

A. I assumed the "capacity-related" portion of all three proxy units was limited to the annual fixed cost of building and owning the combustion turbine. The remainder of the fixed costs of building and operating the nuclear plant and combined cycle plant are were treated as "energy-related." This disaggregation is widely accepted – in fact, it is fundamental to the theoretical underpinnings of the peaker method.

The extra step involved in disaggregating fixed costs is particularly useful when examining the economics of a nuclear unit. In fact, the great majority of the capital investment in a nuclear plant is not attributable to the goal of meeting peak capacity (although a nuclear plant also provides capacity for achieving that goal). Rather, the bulk of the investment in a nuclear plant is attributable to the goal of safely producing energy with low fuel costs.

The uranium used to fuel a nuclear plant costs tends to be less costly than coal, oil or natural gas – and this cost advantage is a key motivation for using this technology. No one would invest in a nuclear unit just to provide capacity during peak hours. The added investment expended on baseload plants is only justified by the potential for minimizing fuel and other variable costs over the operating life of the plant. Consequently, any investment in excess of that required for a peaking plant is appropriately categorized as energy-related. The same logic applies to disaggregating the costs of the combined cycle plant, although the impact is not as significant.

After drawing this distinction, the levelized fixed annual cost estimates in 2017 dollars are summarized in the following table:

Cost per KW/Year	**Nuclear**	**Combined Cycle**	**CT**
Capacity Related	$ 87.12	$ 87.12	$ 87.12
Energy Related	605.61	51.78	0.00
Total	$ 692.72	$ 138.90	$ 87.12

Q. ARE THERE ALSO COMPLICATIONS INVOLVED IN ESTIMATING VARIABLE ENERGY COSTS?

A. Yes. Variable costs can be difficult to deal with, because they are highly dependent on future fuel prices, which are not knowable with any degree of precision.

For example, natural gas prices have exhibited wide fluctuations over both short and medium time frames, although they have exhibited a tendency to trend higher and higher over the long term. The problem with price instability was vividly illustrated during 2016, when natural gas prices plunged by more than 20% during a few months early in the year, and then shot upward by nearly 40% over an even shorter time period later in the year.

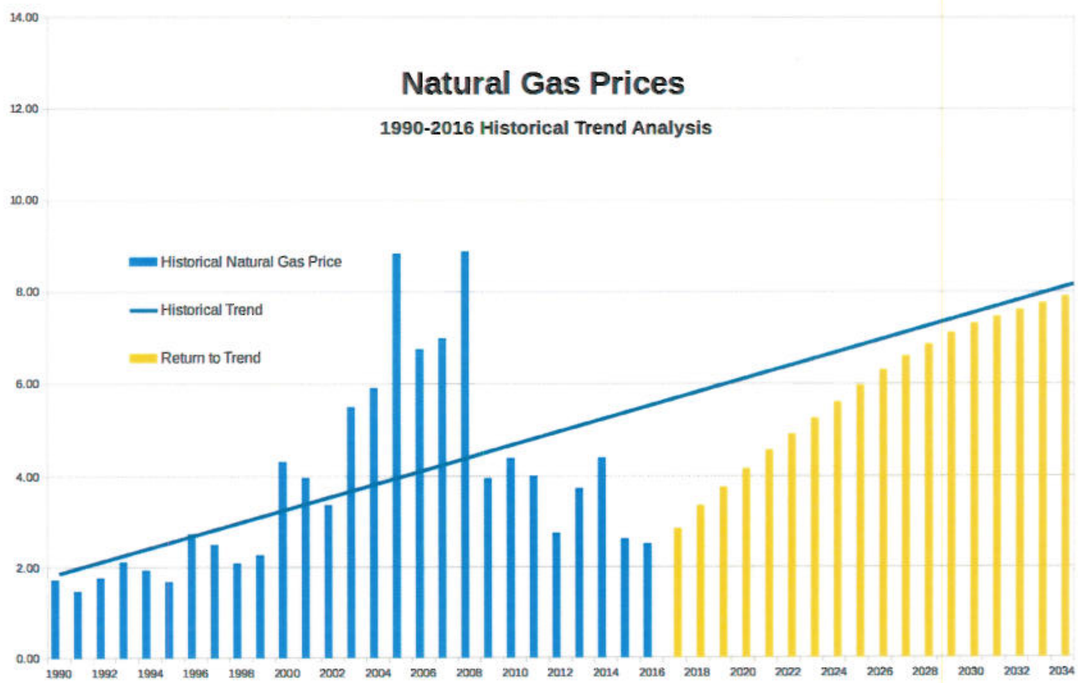
Recently, gas prices returned to very low levels – in fact, the Wall Street Journal had a headline on the front page of its March 15, 2017 edition with the headline "Natural-Gas Glut Deepens." At current prices, gas is so inexpensive it might appear that other options – like coal and nuclear – are undesirable. However, such a conclusion would be premature, since generating plants are 30+ year investments, and the relative merits of each technology need to be evaluated from a long term perspective.

In fact, the instability of natural gas prices, and difficulties associated with predicting these prices is one of the principal disadvantages, or risks, associated with using this fuel source. These risks are important to keep in mind when evaluating the merits of long-term investments in gas-fueled generation relative to other options. Coal has some of the same risk characteristics as gas, but to a lesser degree, since coal prices tend to be more stable and because coal can be sometimes be purchased from coal mines pursuant to multi-year contracts at fixed prices.

The key point is that fuel price assumptions or projections are of critical importance when evaluating generating technologies or estimating energy costs using different fuel sources. In fact, the fuel cost assumptions will at least heavily influence, if not entirely determine, the conclusions that are drawn from an analysis of the relative cost-effectiveness of using different generating technologies.

Q. CAN YOU ELABORATE ON THESE PROBLEMS?

A. Yes. The following graph shows the long term upward trend in natural gas prices from 1990 through 2016. The light blue bars show average gas prices experienced during each of these years, using data obtained from Reuters (1990-96) and the Energy Information Administration (1997-2015). The dark blue line shows the linear trend reflected in that historical data, extended into the future. Finally, the pale yellow bars on the right side of the graph shows what future would look like, if gas prices were smoothly return to the historical trend line and follow the slope of the historical trend line thereafter.



Given the wide fluctuations observed in the historical data (light blue bars), it is apparent that fuel prices cannot be accurately predicted years in advance of when it is purchased. This greatly complicates any attempt to analyze the cost of producing electricity using different technologies or fuels.

This problem is particularly acute when comparing the cost of generating sources that burn fossil fuels with those that don't – like nuclear power, hydro and solar. The extent to which one concludes the latter technologies are higher or lower cost options for ratepayers will be almost entirely dependent upon whatever assumptions or projections are made concerning future fuel prices. A similar problem arises when trying to analyze the impact on ratepayers of obtaining power at fixed long-term prices from a QF compared to having the utility build new generating plants that will burn fossil fuel purchased at prices that are not known in advance, and cannot be predicted with any degree of certainty.

Q. CAN YOU GIVE A REAL-WORLD EXAMPLE OF HOW UNCERTAINTIES CONCERNING FUTURE NATURAL GAS PRICES CAN BE DEALT WITH IN THIS TYPE OF ANALYSIS?

A. Yes. In its 2015 evaluation of the economic viability of its VC Summer nuclear construction project, SCE&G considered several different scenarios concerning potential future gas prices – all of which were higher than the unusually low prices that have recently been observed.[31] SCE&G started with

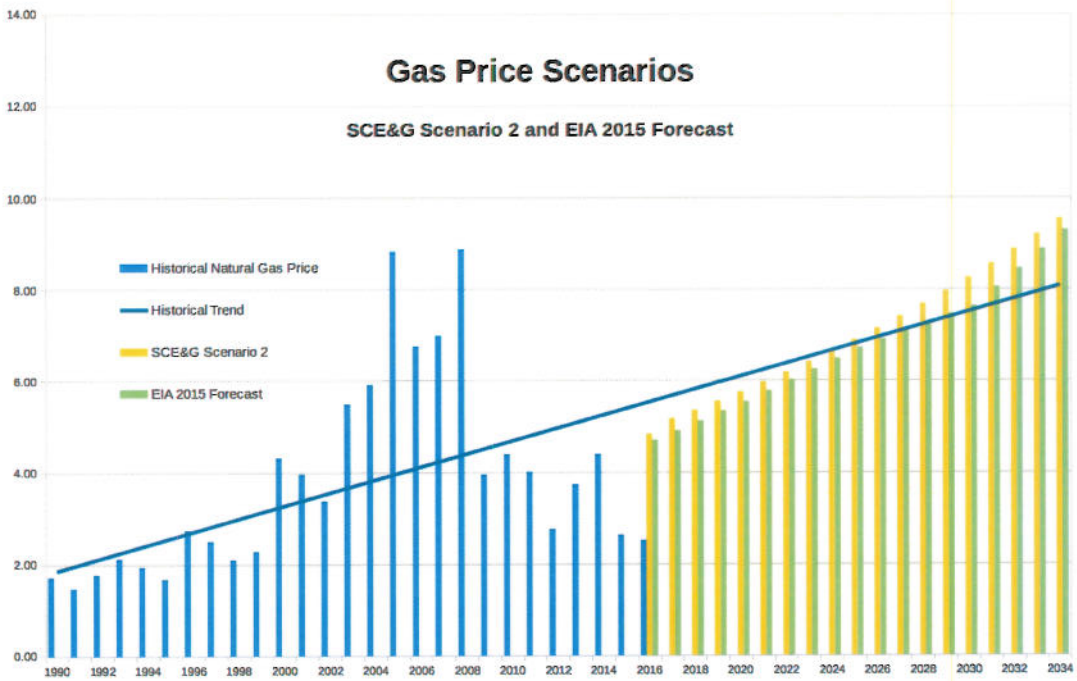
> "two forecasts of natural gas prices at the Henry Hub. One is the current Energy Information Administration (EIA) natural gas forecast reported in their 2015 Annual Energy Outlook (AEO). The second is the proprietary natural gas forecast that SCE&G uses for planning purposes. To develop this forecast, SCE&G uses the forward prices reported for the NYMEX futures contracts over the next three years (i.e., through the end of 2018) and then applies an escalation factor … to forecast prices beyond three years in the future."[32]

The latter forecast, which it described as its "base line forecast" of natural gas prices, was the lowest of three forecasts it developed and used for its evaluation. SCE&G also evaluated the impact of natural gas prices being 50% higher (Scenario 2) or 100% higher (Scenario 3) than this baseline.[33] Scenario 2 and the 2015 EIA baseline forecast were both similar to the historical trend as well as each other, as shown in the following graph:

31 South Carolina Electric & Gas, Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy, May 26, 2015.

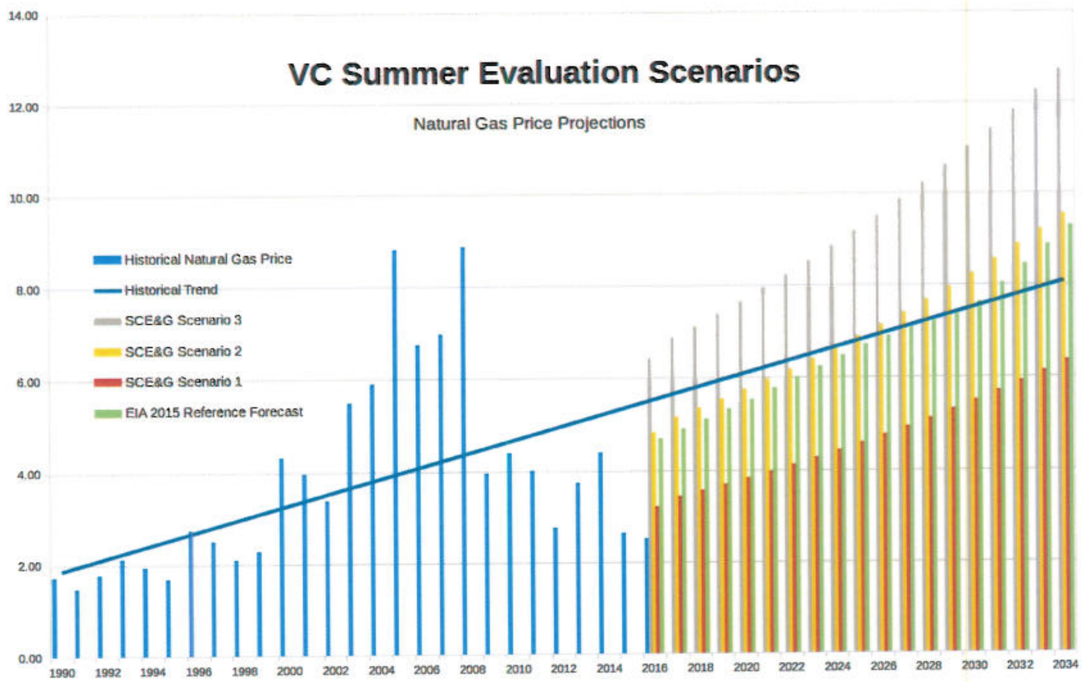
32 Ibid, Page 3.

33 Ibid, Page 3.



Recognizing that “all forecasts of future gas prices are subject to error” SCE&G looked at multiple scenarios, with their Baseline Scenario 1 forming the bottom of the range, Scenario 2 and the EIA's 2015 forecast falling in the middle, and Scenario 3 moving well above the others. Strictly speaking, Scenario 3 was not the highest pricing scenario SCE&G considered, since it also considered the impact of adding an estimate of the cost of carbon to natural gas prices.

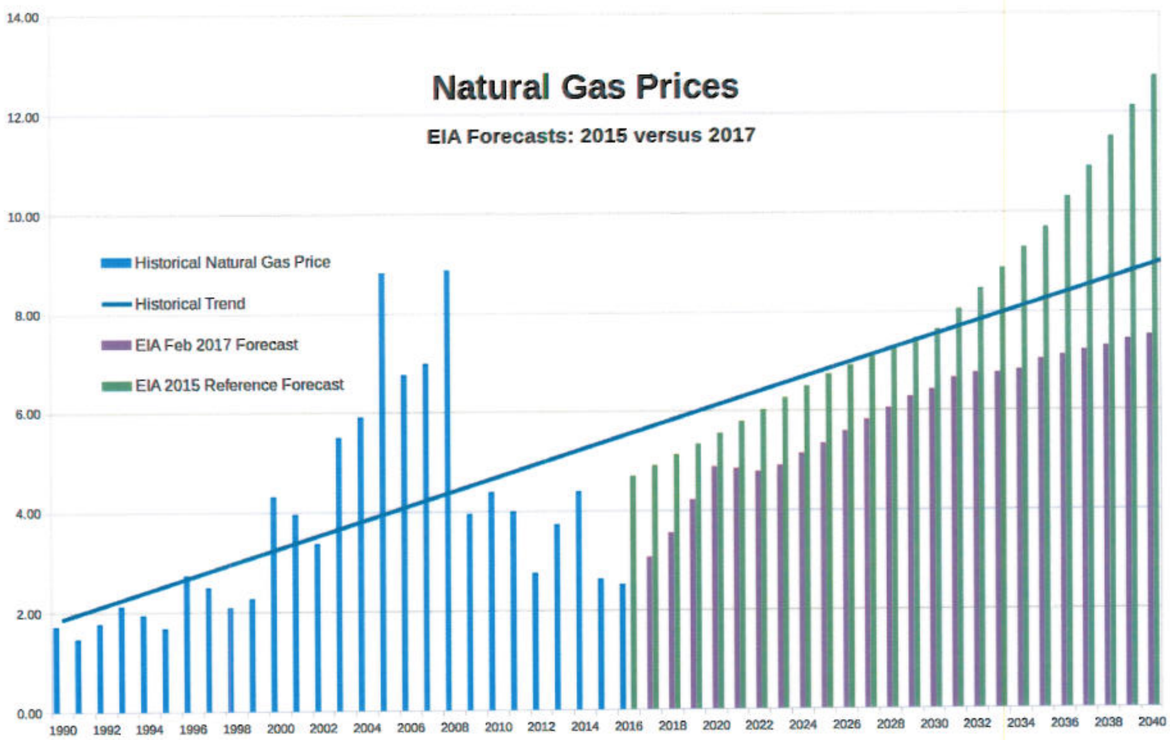
The three SCE&G scenarios are shown in the following graph, which also includes historical data through 2016, and the historical trend line.



When reviewing this graph, it is important to keep in mind that the VC Summer evaluation was completed in June 2015, before most of the 2015 prices, or any of the 2016 prices were known.

Q. HAVE FUEL PRICE FORECASTS DECLINED IN REACTION TO LOWER PRICES?

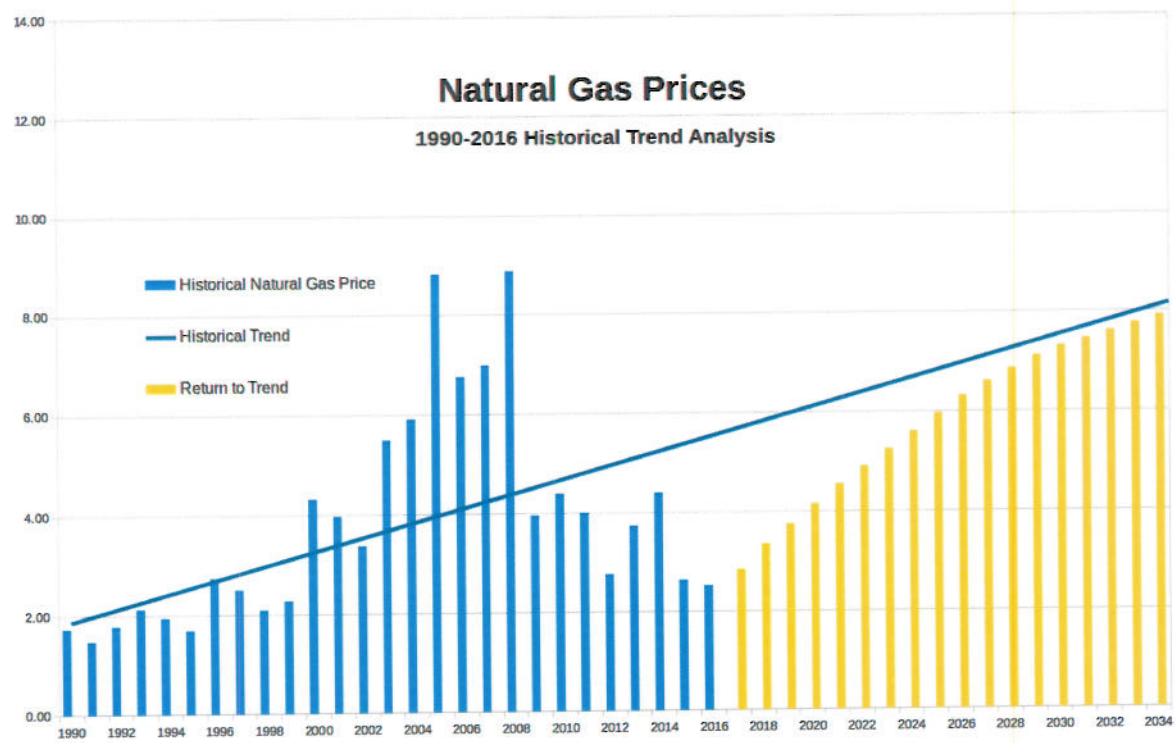
A. Yes. Many forecasters have reduced their expectations for long term future prices, as well as near-term prices. For example, the following graph compares the EIA's 2015 forecast with its 2017 forecast, which was published in March 2017:



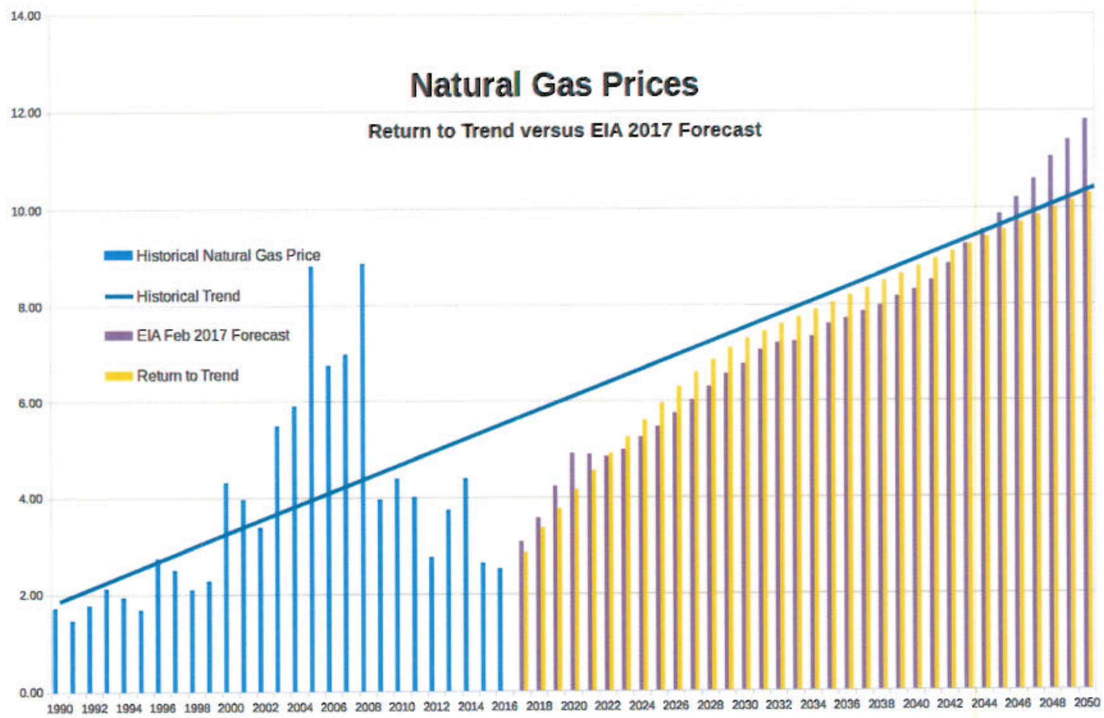
The earlier forecast (light green) is consistently higher than its most recent forecast, because that forecast takes into account the recent experience.

Q. WHAT FUEL PRICES DID YOU USE TO DEVELOP YOUR LONG RUN AVOIDED COST ESTIMATES?

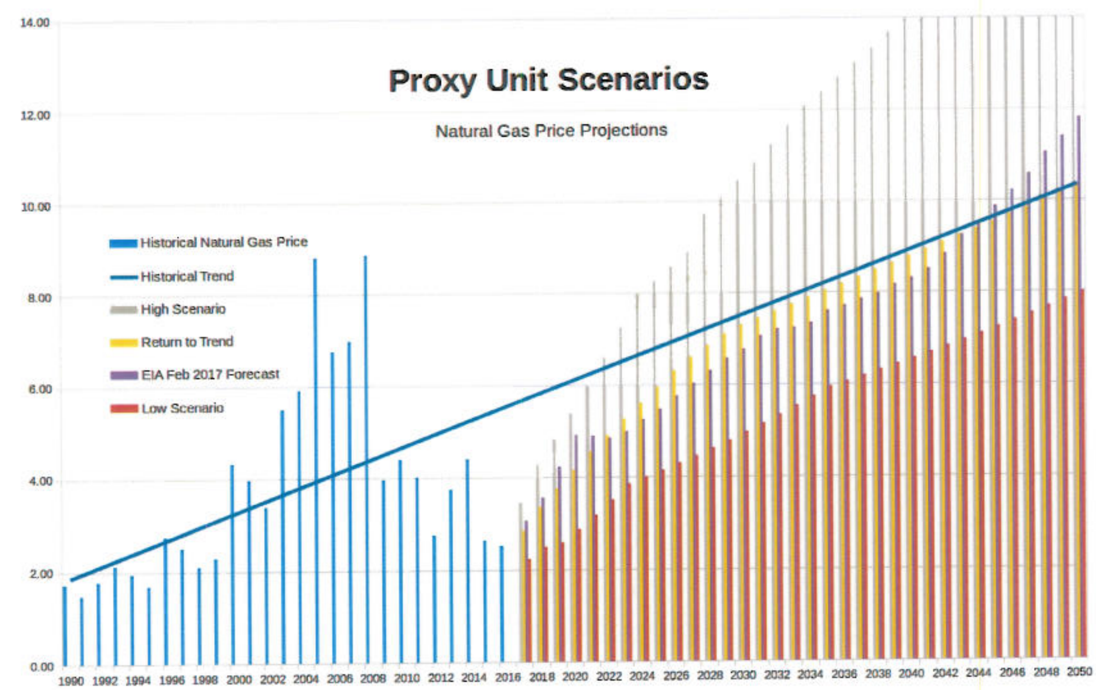
A. I evaluated multiple scenarios, similar to the way SCE&G evaluated its VC Summer units. One scenario assumed natural gas prices gradually return to the historical trend line, then follow the trend line, as shown in this graph:



Another scenario was based upon the EIA's recently published 2017 baseline fuel price forecast, shown in the previous graph. The EIA's 2017 forecast is similar to the trend-based scenario, but the EIA prices sometimes move a little above and sometimes a little below the smoother "Return to Trend" assumptions.



I also bracketed these scenarios with a lower price scenario and a higher one. The lowest scenario was derived from SCE&G's Scenario 1 while the highest price scenario was derived from SCE&G's Scenario 3. However, I lowered all of the prices in the initial years, to reflect the 2015 and 2016 historical data, which wasn't available when SCE&G prepared its VC Summer evaluation. All four scenarios are shown in the following graph:



Q. DID YOU MAKE ANY OTHER ASSUMPTIONS RELATED TO FUEL COSTS?

A. Yes. First, I assumed fuel prices would eventually grow at the overall inflation rate (2%) except in the "High" scenario, where I assumed gas prices would increase 0.5% per year faster than the overall rate of inflation. Second, I assumed a heat rate of 6,500 BTU/kWh for the combined cycle unit and 9,750 BTU/kWh for the combustion turbine unit. Third, I provided an allowance for non-fuel-related variable Operating and Maintenance costs of $2.50 per Mwh for the combined cycle unit, $11.00 per Mwh for the combustion turbine and $2.35 per Mwh for the nuclear unit in 2016 Dollars, before applying a 2% per annum inflation factor. Fourth, I assumed nuclear fuel costs of 1.00 cents per kWh in 2016

Dollars, before applying a 2% per annum inflation factor. This is consistent with, or slightly lower than, the estimates reported by SCE&G in their June 2016 FERC avoided cost report under Subpart C, Section 210 of PURPA.

Q. WHAT ASSUMPTIONS DID YOU MAKE CONCERNING RECOVERY OF FIXED COSTS OVER DIFFERENT TIME PERIODS AND SEASONS?

A. Capacity-related fixed costs are appropriately attributed to peak hours and seasons. To some extent, the same logic holds for energy-related fixed costs, which should also be recovered disproportionately during daytime hours, when energy usage is relatively high.

In the peaker method, this can be accomplished by disaggregating the production modeling output during different time periods and seasons, and by focusing on marginal energy costs, rather than average energy costs. Since marginal costs tend to be high during hours when energy usage is high, the Peaker Method allows fixed energy-related capital costs to be recovered on a granular, hour-by-hour basis, following the hourly variation in marginal energy costs. It should be noted, however, this procedure doesn't necessarily ensure that fixed costs are recovered in their entirety.[34]

I used a similar approach in applying the proxy unit method to achieve a reasonable degree of granularity and ensure all of the fixed costs are taken into account. I first

34 In practice, the results of the Peaker Method can sometimes understate costs, since there is no guarantee the energy cost estimates and capacity cost components will be internally consistent, or sum to the full incremental cost of building and operating a new generating plant – as they are theoretically supposed to.

classified fixed costs in excess of the fixed costs of the Combustion Turbine as energy-related, and then took steps to ensure that energy-related fixed costs were largely recovered during times when energy usage is high, rather than at night, when energy usage tends to be lower.

Q. WHAT ASSUMPTIONS DID YOU MAKE CONCERNING HOURS OF OPERATION?

A. I assumed the nuclear unit would be dispatched at the bottom of the generating stack, and its energy-related costs would be recovered during all 8,760 hours per year. I assumed the combined cycle unit would be dispatched in the middle of the stack (below the combustion turbine) and its energy-related fixed costs would be recovered over 5,110 hours per year. [35] Finally, the combustion turbine would be dispatched last, since it has the highest variable costs. Although I studied multiple scenarios, the most interesting and relevant one assumes CT is dispatched approximately 4 hours per day, or 1,460 hours per year.

Coal plants have traditionally been classified as baseload plants, and dispatched before gas-fired combined cycle plants, which have historically been classified as mid-range plants, while combustion turbines are classified as peakers and expected to be dispatched

35 Spreading the energy-related fixed costs over 5,110 kWh per KW of capacity is similar to assuming the Combined Cycle unit will be dispatched approximately 58% of the time, which is reasonably consistent with the overall system load factor.

last. However the dispatch sequence can vary with changes in fuel prices and the age of each specific plant. In general, generating plants tend to be dispatched more frequently when they are first added to the system and less frequently as they get older, as newer, more fuel-efficient units are introduced to the resource stack. Similarly, gas prices have recently been very low relative to coal prices, causing less efficient coal plants to be dispatched higher in the generation stack (after newly built gas-fired combined cycle plants).

Although somewhat simplified, the approach I used is consistent with the way these different technologies are typically used over their economic life cycle, and it provides a straightforward way of comparing the cost of these different proxy units. However, it is helpful to realize the actual number of hours any given plant will be dispatched will vary as fuel prices change, and it will tend to decline as the plant ages.

Q. WHAT CONCLUSIONS DID YOU REACH CONCERNING PER KWH ENERGY COSTS UNDER THESE SCENARIOS?

A. The costs vary fairly widely, depending upon the technology and long-term natural gas price scenario. Looking first at the Combustion Turbine, the levelized avoided energy costs (including fuel and variable O&M) range from less than 4 cents per kWh to more than 11 cents per kWh, as shown below:

Combustion Turbine Energy-Related Cost per kWh/Year	Natural Gas Price Scenario			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	3.76 ¢	5.14 ¢	4.76 ¢	5.76 ¢
2022 - 2026 Levelized	5.13 ¢	6.39 ¢	6.72 ¢	8.80 ¢
2027 - 2031 Levelized	6.09 ¢	7.79 ¢	8.31 ¢	11.16 ¢

With the Combined Cycle plant, the sensitivity to fuel prices isn't quite as extreme, since the unit has a better heat rate (burns less fuel) and because the avoided energy costs include energy-related fixed costs, which don't vary with fuel prices. This greater stability can be seen below:

Combined Cycle Energy-Related Cost per kWh/Year	Natural Gas Price Scenario			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	2.94 ¢	3.83 ¢	3.59 ¢	4.23 ¢
2022 - 2026 Levelized	3.78 ¢	4.59 ¢	4.80 ¢	6.13 ¢
2027 - 2031 Levelized	4.33 ¢	5.43 ¢	5.76 ¢	7.60 ¢

Not surprisingly, the Nuclear plant is the least sensitive to fuel prices and the most stable over time, because most of the costs are fixed and levelized:

Nuclear Energy-Related Cost per kWh/Year	Natural Gas Price Scenario Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	8.22 ¢	8.22 ¢	8.22 ¢	8.22 ¢
2022 - 2026 Levelized	8.35 ¢	8.35 ¢	8.35 ¢	8.35 ¢
2027 - 2031 Levelized	8.50 ¢	8.50 ¢	8.50 ¢	8.50 ¢

The Combined Cycle unit generally has the lowest costs and therefore I've primarily focused on these cost estimates when making benchmark comparisons to the Company's proposed rates.

However, each technology has some advantages and disadvantages. The Combustion Turbine tends to be more cost effective in meeting loads of short duration[36] while nuclear technology provides the greatest price stability over the very long term. This greater stability has historically proven to be an advantage for nuclear plants – even ones that encountered major schedule delays and cost over-runs ultimately became more cost effective in the latter part of their life cycle. Even troubled plants, with high construction costs, looked better over time, because the construction cost was largely fixed, while the cost of alternative fuels increased greatly as the years went by.

36 If a generating unit is going to be dispatched less than approximately 1,700 hours a year, the benefit of the lower installed cost of the CT outweighs the burden of its higher heat rate and fuel costs.

Avoided Costs Compared to the Proposed QF Rates

Q. CAN YOUR BENCHMARK AVOIDED COST ESTIMATES BE COMPARED TO THE COMPANY'S PROPOSED QF RATES?

A. Yes. However, to directly compare the Benchmark Avoided Cost estimates to SCE&G's QF rates, it is appropriate to first assign the capacity-related costs to the seasonal peak and off-peak time periods specified in SCE&G's QF tariff.

I began this process by reviewing the Company's hourly loads for the years 2000-2015 using data submitted by the Company to the FERC on form 714.

I determined that approximately 82% of the most extreme system peaks (at or above 99% of the annual coincident system peak) occurred during the months of June through September, while the remaining 18% occurred during the months of December, January and February, as shown in the following table:

Magnitude of Peak	June - September	December - February	Other
Hourly Load +> 99% of Annual Peak	81.6%	18.4%	0.0%
Hourly Load +> 97% of Annual Peak	91.2%	8.8%	0.0%
Hourly Load +> 95% of Annual Peak	90.6%	9.4%	0.0%
Hourly Load +> 90% of Annual Peak	93.3%	6.6%	0.1%

Consistent with this data, I allocated 82% of the capacity-related fixed costs to the months of June – September, and the remaining 18% was allocated to the months of December – February.

I also provided a small allowance for line losses and costs (5% for distribution and 1% for transmission) that are avoided by obtaining power from QF facilities at locations that are more diversified than, and closer to customer loads than, the typical utility generating unit. This benefit is difficult to estimate precisely, since it varies depending upon voltage level and where the QF interconnects to the system, but I didn't think it should simply be ignored.

Q. HOW DO THE BENCHMARK AVOIDED COST ESTIMATES COMPARE TO THE COMPANY'S PROPOSED QF ENERGY RATES?

A. The Company's proposed QF rates are generally lower than my benchmark avoided cost estimates – and under some scenarios and some time periods, the discrepancy is quite wide. For simplicity, the following tables focus on the Combined Cycle Proxy Unit avoided cost estimates. Similar conclusions would reached using the other technologies, except those technologies tend to have higher per-kWh costs, as discussed earlier. Each table compares the Company's proposed QF energy rates to the avoided energy cost during a specific 5 year period, with different rows used to report the results assuming different fuel price scenarios.

2017-2021 SCE&G Proposed QF Energy Rates vs. Benchmark Avoided Energy Costs using Different Scenarios		
Summer	On Peak	Off Peak
Proposed QF Rate	3.384 cents	2.845 cents
Avoided Cost – Low Scenario	3.81 cents	2.19 cents
Avoided Cost – EIA 20017 Forecast	4.74 cents	3.13 cents
Avoided Cost – Return to Trend	4.49 cents	2.87 cents
Avoided Cost – High Scenario	5.16 cents	3.55 cents
Non-Summer	On Peak	Off Peak
Proposed QF Rate	3.483 cents	3.170 cents
Avoided Cost – Low Scenario	3.37 cents	2.15 cents
Avoided Cost – EIA 20017 Forecast	4.30 cents	3.09 cents
Avoided Cost – Return to Trend	4.05 cents	2.83 cents
Avoided Cost – High Scenario	4.72 cents	3.51 cents

During the first five years, there is a significant discrepancy between the Company's proposed QF energy rates and the long run avoided energy costs during every scenario, and nearly every time period. The only exceptions are the off-peak time periods under the Low fuel price scenario.

A similar pattern occurs in the next five year period, except the discrepancies tend to be even larger, and the lone exception is the Off Peak Non-Summer period under the Low fuel price scenario:

2022-2026 SCE&G Proposed QF Energy Rates vs. Benchmark Avoided Energy Costs using Different Scenarios

Summer	On Peak	Off Peak
Proposed QF Rate	3.648 cents	2.679 cents
Avoided Cost – Low Scenario	4.69 cents	3.07 cents
Avoided Cost – EIA 20017 Forecast	5.54 cents	3.92 cents
Avoided Cost – Return to Trend	5.76 cents	4.15 cents
Avoided Cost – High Scenario	7.16 cents	5.54 cents
Non-Summer	On Peak	Off Peak
Proposed QF Rate	3.200 cents	2.726 cents
Avoided Cost – Low Scenario	4.25 cents	3.04 cents
Avoided Cost – EIA 20017 Forecast	5.10 cents	3.88 cents
Avoided Cost – Return to Trend	5.32 cents	4.10 cents
Avoided Cost – High Scenario	6.72 cents	5.50 cents

In the final five year period there is an even larger gap between the proposed QF rates and the avoided energy costs, and the gap occurs under every fuel price scenario and every time period, with no exceptions.

2027-2031 SCE&G Proposed QF Energy Rates vs.
Benchmark Avoided Energy Costs using Different Scenarios

Summer	On Peak	Off Peak
Proposed QF Rate	4.070 cents	3.040 cents
Avoided Cost – Low Scenario	5.27 cents	3.65 cents
Avoided Cost – EIA 20017 Forecast	6.42 cents	4.81 cents
Avoided Cost – Return to Trend	6.77 cents	5.15 cents
Avoided Cost – High Scenario	8.70 cents	7.09 cents
Non-Summer	On Peak	Off Peak
Proposed QF Rate	3.587 cents	2.935 cents
Avoided Cost – Low Scenario	4.83 cents	3.61 cents
Avoided Cost – EIA 20017 Forecast	5.98 cents	4.77 cents
Avoided Cost – Return to Trend	6.33 cents	5.11 cents
Avoided Cost – High Scenario	8.26 cents	7.04 cents

In the final five-year period, the discrepancy ranges from just under 1 cent in the Off Peak period under the Low Scenario to more than 5 cents per kWh in the On Peak Summer period under the High Scenario.

Q. HOW DO THE BENCHMARK AVOIDED COST ESTIMATES COMPARE TO THE COMPANY'S PROPOSED QF CAPACITY RATES?

A. The proposed rates are significantly lower than the long run avoided capacity costs associated with building and operating new generating plants, as this next table shows:

SCE&G Proposed QF Capacity Rates vs. Benchmark Avoided Capacity Costs				
	Summer (Jun – Sep)		Other (Oct – May)	
	Proposed QF Rate	Avoided Cost	Proposed QF Rate	Avoided Cost
Critical-Peak	$ .01965	$ .2854	$ .00675	$ .0854

Q. WHY ARE THE COMPANY'S PROPOSED CAPACITY RATES SO MUCH LOWER THAN YOUR CAPACITY COST ESTIMATES?

A. Most of this discrepancy is attributable to the inputs and assumptions used by the Company when it the DRR method, particularly with respect to the way it simplified its analysis of its revenue requirement.

In developing its QF capacity rate, SCE&G started with its existing fleet of generating units and planned purchases, and it considered changes that would occur if it received 100 MW's of capacity from a QF at zero cost. Under the DRR method, the idea is to estimate the change in its revenue requirements that would occur as a result of this extra "free" capacity during the 15-year period. However, the Company used simplified assumptions which did not analyze its revenue requirements in detail, and did not adequately consider some of the things it would probably implement, in actual practice, in order to minimize the revenue requirement burden on it retail customers.

The simplified assumptions it adopted effectively assumed nearly everything about its operations would be identical under both scenarios, during some years. The result of these simplifying assumptions was to effectively assume there would be few, if any, changes to its revenue requirement when comparing the two scenarios. This ultimately translated into low, or zero, avoided capacity cost estimates, as well as low energy cost estimates.

Q. CAN YOU ELABORATE ON THESE SIMPLIFYING ASSUMPTIONS?

A. Yes. For example, in its Base plan the Company assumed it would purchase 300 MW of capacity during each of the years 2017 through 2019 (prior to completion of the first nuclear unit, which it assumed would come on line in 2020). In its workpapers, it assumed complete flexibility to extend or increase its purchases of power from other firms, as needed, but it failed to analyze the implications of this flexibility with respect to other assumptions concerning its revenue requirements.

Formulas inside the Company's workpapers effectively assume it has complete flexibility to purchase more power as needed, if the nuclear units are delayed. This assumption is reasonable and, in my opinion, appropriate. However, it has an important implication which the Company overlooked, or failed to adequately consider in developing other assumptions used in its DRR analysis. It's reasonable to assume the Company has the ability to purchase power if the nuclear units are delayed – but that necessarily implies a wholesale market for power exists. That market will also enable the Company to reduce its revenue requirement if the nuclear units are <u>not</u> delayed. Those units will provide substantial excess energy generating capacity during the initial years after the nuclear units come on line. In turn, this means it will have the option of selling power (instead of buying it, as it would need to do if the nuclear units were delayed). The ability to sell firm energy at a profit (over and above the variable costs) will help the Company reduce its revenue requirement, thereby easing the burden borne by its retail customers, who will be paying the full cost of the nuclear units, even though they are capable of generating more energy than is needed to meet the Company's native load.

Q. HOW DID THIS OVER-SIMPLIFICATION AFFECT ITS PROPOSED QF RATE CALCULATIONS?

A. Assuming the nuclear units are not delayed, the Company will have excess energy available which will be able to sell on the wholesale market to other utilities. There is every reason to assume the Company will engage in power sales once the new nuclear units are operating, because this will lower the revenue burden borne by its retail customer. Because the Company failed to include these transactions in its DRR analysis, it also failed to evaluate the impact of changes to these transactions which would occur if the 100 MW bock of "free" QF power were available.

Under the scenario with the 100 MW block of QF power, the Company's ability to profitably sell firm energy to other utilities would be further enhanced, allowing it to further reduce its revenue requirement. The Company's failure to analyze the synergies between the new nuclear units and the "free" block of QF power, and implement appropriate input assumptions which reflect the beneficial impact of this combination on its revenue requirements, led it inaccurately estimate its avoided capacity cost as zero (and to underestimate its avoided energy costs). Simply stated, by simplifying away this aspect of its future revenue requirements, it underestimated the true economic value of the 100 MW block of QF power.

In essence, if the Company had used more realistic assumptions that took this aspect of its situation into account, the Company's DRR method would have demonstrated that the 100 MW block of capacity has a positive, non-zero value in every year. To accurately study the value of the extra 100 MW of "free" capacity it is necessary to analyze the impact of wholesale transactions on its avoided energy calculations. The 100 MW "free" block of capacity brings with it 876,000 MWH of energy, which would enhance the Company's ability to profitably market firm power from its existing fleet of generating units. This would further reduce its revenue requirement (assuming the interests of retail ratepayers are protected by minimizing the revenue requirement under each scenario). In effect, this additional "free" energy enhances its ability to profitably sell energy to other utilities on terms that help reduce the revenue burden borne by its retail ratepayers. This improvement in the retail ratepayers' situation should have been analyzed in greater detail, and if this had been done, it would have demonstrated that the block of QF capacity and energy has a greater value than was calculated using the Company's simplified assumptions.

Q. ARE THE SORT OF DETAILED CALCULATIONS AND ASSUMPTIONS YOU ARE DESCRIBING MORE CONSISTENT WITH THE THEORETICAL UNDERPINNINGS OF THE DRR METHOD?

A. Yes. In preparing the DRR analysis, both scenarios are supposed to be adjusted as necessary to minimize the revenue requirement burden that is placed on retail customers. Recall that under the DRR method, a planning expansion model is used to develop generation expansion plans. The reason a model is used (rather than simply inputting the current expansion plan) is to enable the analyst to carefully study multiple different expansion plans, and select the one that best minimizes the revenue requirement under the circumstances of a given scenario.

The Company has failed to utilize the full power of the modeling process to evaluate multiple expansion plans, or to adequately analyze the impact of the block of QF power under each expansion plan. This is particularly evident with respect to the VC Summer plant. This project has been plagued by numerous delays and cost overruns, which are largely outside of the Company's control. While everyone hopes the project will be completed within its current budget and schedule, there is no certainty this will happen. To the contrary, given the delays that have already occurred, and the history of other nuclear projects which have encountered delays and cost overruns, there is a significant risk the expansion plan assumed in both the Company's “base” and “change” scenarios will not materialize. To account for this uncertainty, additional computer modeling should have been used to evaluate the impact on the expansion plan and revenue requirement if further delays were to occur.

The modeling process should be used to evaluate the impact of further delays on both the “base” scenario and the scenario that includes a block of “free” QF power. It isn't sufficient to ignore this uncertainty, or to simply assume the impact on the expansion plan and Prosym output would be largely identical in all cases. To the contrary, there is reason to anticipate that scenarios that include the QF power will provide the Company with additional flexibility and resiliency, enabling it to better minimize the adverse impact on ratepayers if one or both nuclear units were to be delayed.

To accurately measure the avoided cost implications of this greater flexibility, several scenarios should have been evaluated, corresponding to different assumptions concerning the timing of when the VC Summer units are completed, and the cost and availability of alternative capacity and energy sources which can be inserted into the expansion plan in order to compensate for the delay. In each case, the “base” and “change” scenarios should be carefully evaluated to adopt the expansion plan that best minimizes the revenue requirement under those conditions, and Prosym used to estimate the impact on energy costs given that expansion plan. This additional, more robust computer modeling would have enabled the Company to draw more accurate and meaningful conclusions concerning the full economic benefits that will result from obtaining the block of QF power (the cost that can be avoided by purchasing the QF power.)

Q. CAN YOU CLARIFY THE DIFFERENCE BETWEEN USING THE FULL POWER OF COMPUTER MODELING AND SIMPLY ASSUMING THE EXPANSION PLAN WILL BE LARGELY THE SAME IN EACH CASE?

A. Yes. A generation expansion model allows the analyst to evaluate different scenarios and possible responses to those scenarios, and then identify the optimal response under each scenario. One example of how this modeling capability can be useful is to analyze circumstances that cannot be known in advance, but which can be evaluated on a probabilistic basis. The Company already implements a similar approach with respect to uncertainties concerning outages of its generating units by running Prosym under different outage scenarios. It could have done something similar to evaluate the inherent uncertainties involved with its nuclear construction project. History shows that the timing (and cost) of nuclear plants is inherently subject to a degree of uncertainty, just as weather events and generating station outages are subject to uncertainty.

A modeling approach can easily handle the timing uncertainties associated with the timing of the nuclear units, by studying multiple scenarios, with variations in the timing of when each unit becomes operational and injecting power into the grid. In turn, the revenue requirement implications of each scenario can (and should) be analyzed to compare the revenue requirement under that scenario both with and without the "free" block of QF power. The difference between the two revenue requirements (assuming each has been minimized to the maximum extent feasible) would provide an estimate of the true economic value (or avoided cost) of the QF power under that scenario.

Q. DO THE COMPANY'S WORKPAPERS PROVIDE SOME EVIDENCE CONCERNING HOW ITS REVENUE REQUIREMENTS WOULD BE REDUCED BY THE "FREE" BLOCK OF QF POWER?

A. Yes. The workpapers show that the Company will be in a strong position to profitably sell blocks of firm energy and capacity under scenarios where the nuclear units are completed in a timely manner. For example, assuming the existing construction schedule, with no further delay in the nuclear units, the "Base" scenario shows a Reserve Margin of 17.4% in 2020, 27.5% in 2021, 25.7% in 2022, 23.3% in 2023, and 21.6% in 2024. Considering that a reserve margin during peak hours of about 14 to 17% is often considered adequate, these reserve margins are well in excess of the Company's actual capacity needs during the peak hours.

The high reserve margins are directly attributable to the "lumpiness" of the planned nuclear plant additions. The amount of energy that will be available in excess of the requirements of its own customers will be even greater than implied by the reserve margin percentages, since the nuclear units will be operated around the clock, and are capable of generating enormous amounts of energy at very low variable cost.

The "change" scenario puts the Company into an even stronger position to profitably sell firm energy to other utilities. Under that scenario, it will have Reserve Margins of 19.4% in 2020, 29.4% in 2021, 27.6% in 2022, 25.2% in 2023, and 23.4% in 2024. By calculating the difference in the (appropriately minimized) revenue requirement under each scenario, an accurately developed comparison will show that the extra block of 100 MW of QF energy will further enhance the Company's ability to profitably sell firm energy (at a price that exceeds its variable cost, thereby reducing the revenue burden borne by its retail customers).

Under the DRR method, the burden on ratepayers should be minimized under every scenario, so that a valid "apples to apples" comparison is made when calculating the differential between having the QF power and not having it. Moreover, the specific strategy, or the degree to which a strategy is implemented, might differ, depending on the circumstances. In scenarios that include the 100 MW block of "free" capacity, the Company have a greater ability to profitably sell firm energy when the nuclear units are complete.

In all scenarios where excess energy-generating capacity exists, the burden on ratepayers should be minimized. To achieve this, all relevant options should be evaluated, and the strategy that best minimizes the revenue requirement should be adopted. In the scenarios where the nuclear units are completed as scheduled, this could potentially involve selling blocks of capacity and energy to other utilities on a multi-year basis, it could involve selling a "slice" of its system for a specified term, it could involve selling a fractional share of the output from specified generating units (e.g. the VC Summer nuclear units) for a specified number of years, or it could involve selling energy to the highest bidder, endeavoring to generate as much income as possible from the Company's under-used generating assets.

In all cases, the various scenarios would need to be examined to see how transactions with other utilities affect its revenue requirements. Correctly implemented, when comparing the "Base" and "Change" scenarios, the difference in the capacity-related revenue requirements will be significantly larger than zero in every year – contrary to the amounts calculated under the Company's oversimplified approach. Although I have been focusing on the capacity-related revenue requirement, the analysis should consider the effect of each strategy the Company's energy-related revenue requirement, as well. In fact, the optimal strategy is likely to involve the sale of firm energy, rather than the sale of pure capacity, and thus the end result will be to increase both the avoided capacity cost and the avoided energy cost, relative to the over-simplified assumptions used by the Company in developing its proposed QF rates.

Q. DO THE COMPANY'S WORKPAPERS PROVIDE SOME INDICATIONS OF HOW THE QF POWER WILL AFFECT THE REVENUE REQUIREMENT IF THE NUCLEAR UNITS ARE DELAYED?

A. Yes. Formulas inside the Company's workpapers suggest the the QF power will be quite helpful under this scenario. Using these formulas, and assuming for illustrative purposes that both nuclear units are delayed by two years, the “Base” scenario automatically adjusts to reflect the purchase of 450 MW of power in 2020, 575 MW in 2021 and 100 MW in 2022. The corresponding figures under the “Change” scenario are purchases of just 350 MW in 2021, 475 MW in 2021 and 0 MW in 2022.

In effect, the 100 MW of “free” capacity provides a valuable hedge against the uncertainties associated with the nuclear construction program, and it would reduce the cost of meeting the Company's capacity needs in the event of a construction delay. The workpapers are not sufficiently detailed to accurately analyze the full value of the 100 MW block of power, but it is obviously well in excess of the amounts calculated by the Company using its simplified assumptions. The exact magnitude will depend on what additional assumptions are used, and how the workpapers are refined to incorporate these assumptions, in order to more accurately estimate the (minimized) revenue requirement under each scenario. Of particular importance would be the assumptions that are adopted concerning the cost of purchasing capacity and energy relative to the amounts received when selling capacity and energy (these numbers wouldn't necessarily be identical). Also of importance would be the assumptions that are adopted concerning the impact of timing differences on these amounts. In general, one would expect to receive a higher price when contracting for a sale of capacity or firm energy several years in advance of the buyer's need, and one will face greater uncertainty concerning the price that will need to be paid when purchasing capacity or firm energy, if the need for the purchase arises unexpectedly, or the transaction needs to be arranged on an urgent basis.

Q. DO THE SIMPLIFIED ASSUMPTIONS USED BY THE COMPANY ADEQUATELY DEAL WITH THESE COMPLICATIONS?

A. No. The Company's input assumptions largely ignored these complications. Instead, it assumed there would be little or no change to its revenue requirement if it had the extra 100 MW of QF capacity available, and it therefore calculated a minimal difference in its revenue requirements when comparing the “base” scenario to the “change” scenario.

The low costs the Company developed compared to the benchmark avoided capacity and energy costs are a direct result of these oversimplified assumptions. Its conclusion that QF capacity has no value (zero avoided capacity costs) and its proposal to set QF energy rates far below the actual costs of operating a gas-fired generating plant are a direct result of this oversimplification. In essence, by assuming very little difference between the two plans, and ignoring the potential to profitably engage in transactions with other utilities, the Company calculated very little difference in the two revenue requirement scenarios, which resulted in a very low estimate of its avoided costs.

Q. WHY SHOULD THE COMMISSION BE CONCERNED ABOUT THIS OVERSIMPLIFICATION?

A. This simplified approach is fundamentally inconsistent with the purpose of regulating QF rates in the first place – to encourage QF development and to prevent utilities from discriminating against small power producers in favor of their own facilities. PURPA explicitly requires QF rates to reflect the "incremental cost to the electric utility of electric energy or capacity or both which, BUT FOR the purchase from the QF or QFs, such utility would generate itself or purchase from another source." [37]

The purpose of imposing this requirement on utilities is clear – it establishes a reasonable standard for setting the prices to be paid to QF's – one which is equivalent to the full incremental cost the utility incurs when it builds and operates its own generating units, or purchases power from other utilities. It would defeat the entire purpose of this requirement if utilities were free to set the capacity price at zero during some years,

37 18 CFR sec. 292.101(b)(6).

merely by treating their existing and planned capacity as a given, and assuming no changes will be made to these existing plans if power is obtained from a QF.

Q. ARE YOU AWARE OF ANY OTHER INSTANCES IN WHICH A UTILITY HAD EXTRA CAPACITY DURING CERTAIN YEARS, AND PROPOSED ZERO AVOIDED CAPACITY COSTS DURING THOSE YEARS?

A. Yes. The North Carolina Utilities Commission recently rejected proposals to avoided capacity costs at zero in certain years. DEC, DEP and Dominion North Carolina Power ("DNCP"), argued their avoidable capacity costs were zero during some years, because they already had enough capacity during those years. While the specifics differ, the arguments offered in that case are similar to those used by SCE&G to justify its proposed QF rates in this proceeding:

> In support of DEC, DEP and DNCP's proposal to include zeroes in their avoided capacity cost calculations during the early years of the planning horizon, DEC/DEP witness Bowman testified that PURPA was not intended to force utilities to pay for capacity that they do not otherwise need ...DEC/DEP suggest that ...the avoided cost rate should include only the annual fixed capacity costs for years in which an actual capacity need exists as determined by the utilities' most recently filed IRP.
>
> ...witness Petrie asserted that DNCP has all the capacity it needs and that it will not avoid any capacity costs if new QFs commence operation during this time period.[38]

38 North Carolina Utilities Commission, Order Setting Avoided Cost Input Parameters, Docket No. E-100, Sub 140, December 31, 2014, Page 32.

After reviewing the utilities' arguments it ultimately rejected the proposal to assume a zero avoided capacity cost during years in surplus capacity existed:

> It is inappropriate in this docket, when employing the peaker method, to require the inclusion of zeroes for the early years when calculating avoided capacity rates..[39]
>
> The Commission determines ...that the avoided cost rate should [not] be reduced as advocated when the utility shows no need to acquire QF capacity when QF contracts are entered into.
>
> ...the FERC rejected claims bearing some similarities to the claims made by the utilities in this case, that a short-term lack of need because of a recently built plant justifies not making capacity payments. In Hydrodynamics (146 FERC ¶ 61,193), the FERC explained that avoided cost rates need not include the cost for capacity in the event that the utility's demand or need for capacity is zero. However, the FERC made clear that the time period over which the need for capacity needs to be considered is the planning horizon.
>
> ...Based on the facts of Hydrodynamics, the FERC determined that if a utility needs capacity over its planning horizon, i.e., it can avoid building or buying future capacity by virtue of purchasing from a QF, the avoided cost rates must include the full cost of the future capacity that would be avoided. The Commission is concerned that including zeroes ...may not equal the full cost of a CT and system marginal energy costs as a proxy for a baseload plant, as intended by the peaker method. ...It also is significant that the utilities typically are not penalized for having capacity that results in a reserve margin at or above the upper range of what is optimal ...each of the three shows the need for more than 3,000 MW of generation over the next 15 years, and it is that future generation that QFs can defer or avoid.[40]

39 Ibid, Page 8.

40 Ibid, Page 35.

Recommendation

Q. What do you recommend to resolve the QF issues in this proceeding?

A. The Company is proposing unreasonably low QF rates which will not advance the interests of retail ratepayers or the public interest. I recommend the Commission reject these rates, because they will not adequately compensate QF's, they will not encourage small power production within SCE&G's service area, and they will not adequately achieve the goals of PURPA.

Instead, I recommend the Commission require the Company to collaboratively work with ORS and other interested parties to develop higher, more accurate QF rates. This can be accomplished by modifying the inputs and assumptions used in the DRR analysis, to more accurately analyze and minimize the revenue requirements under each scenario.

In the alternative, the Commission should adopt QF rates in this proceeding which are closer to those it has approved for Duke Carolinas and Duke Progress, as well as the long run incremental cost of building and owning a new generating unit, based upon the benchmark avoided cost information I provided in my testimony.

Q. Does this conclude your direct testimony, which was prefiled on March 22, 2017?

A. Yes.

BEFORE
THE PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA
DOCKET NO. 2017-2-E

IN RE: Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company	))))))	**CERTIFICATE OF SERVICE**

I, Carrie A. Schurg, an employee of Austin & Rogers, P.A., certify that I have served copies of the Direct Testimony of Dr. Ben Johnson on behalf of Intervenor, South Carolina Solar Business Alliance, LLC, Cover Sheet and this Certificate of Service, via electronic mail on March 22, 2017.

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March 22, 2017
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